PB82-202573

Fossil Fuel Fired Industrial Boilers - Background Information Volume 1: Chapters 1-9

(U.S.) Environmental Protection Agency
Atlanta, GA

Mar 82

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-82-006a
March 1982

PB82-202573

Air

EPA

Fossil Fuel Fired Industrial Boilers– Background Information

Volume 1: Chapters 1-9

Draft EIS

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NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA 450/3-82-006a,b	2.	3. RECIPIENT'S ACCESSION NO. PB82 202573
4. TITLE AND SUBTITLE Fossil Fuel-Fired Industrial Boilers - Background Information		5. REPORT DATE March 1982 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Office of Air Quality Planning and Standards U. S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-3058
12. SPONSORING AGENCY NAME AND ADDRESS DAA for Air Quality Planning and Standards Office of Air, Noise, and Radiation U. S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED 14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES

16. ABSTRACT

This document provides background information for the fossil fuel-fired industrial boiler source category. Fossil fuels considered include coal, oil and natural gas. Background information for industrial boilers includes a survey of boiler types, sizes, operating characteristics, and existing State and Federal regulations. Uncontrolled emissions of particulate matter, sulfur dioxide and nitrogen oxides are quantified and factors affecting these emissions are discussed. Control technologies for particulate matter, sulfur dioxide and nitrogen oxides are identified and discussed with respect to the technologies' applicability to industrial boilers, developmental status, and factors affecting performance. Emissions data for each technology are also presented. Finally, environmental, energy and cost impacts of applying these technologies to fossil fuel-fired industrial boilers are presented and discussed. This information was developed in support of potential new source performance standards for industrial boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution Pollution control Standards of performance Fossil fuel-fired industrial boilers	Fossil fuel-fired industrial boilers Air pollution control	

18. DISTRIBUTION STATEMENT Release unlimited. Available from EPA Library (MD-35), Research Triangle Park, North Carolina 27711	19. SECURITY CLASS (This Report) unclassified	21. NO. OF PAGES 869
	20. SECURITY CLASS (This page) unclassified	22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

EPA-450/3-82-006a

Fossil Fuel Fired Industrial Boilers– Background Information
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Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

March 1982

This report has been reviewed by the Emission Standards and Engineering Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, or from National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161.

For sale by Superintendent of Documents
U.S. Government Printing Office
Washington, DC 20402

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1.0 OVERVIEW

This document was prepared to provide the public and industry with background information on the industrial boiler source category in support of potential new source performance standards. Fossil fuels discussed and analyzed include coal, oil, and natural gas. Background information for nonfossil fuel fired boilers (wood, solid waste, bagasse and fossil/nonfossil mixtures) is included in a separate document EPA 450/3-82-007.

This document contains information on the use of industrial boilers in different industries and an assessment of controlled and uncontrolled emissions from different configurations of boilers firing fossil fuels. Cost and environmental assessments for several model boiler configurations to meet alternative control levels are also presented.

2.0 INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as control alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which ". . . causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect ". . . the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

    a. 25 percent of the listed categories by August 7, 1980.
    b. 75 percent of the listed categories by August 7, 1981.
    c. 100 percent of the listed categories by August 7, 1982.

    A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. EPA is required to review the standards of performance every 4 years and, if appropriate, revise them.

3. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to 6 months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any non-air-quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other

States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States and local agencies if authorized by State law are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> . . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is

> achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act. (Section 169(3))."

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(i) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to 3 years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources. The Administrator ". . . shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the non-air-quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "control alternatives." These control alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each control alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible control alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected control alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected control alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the background information document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may result in additional costs for water treatment and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decisionmaking process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969." (15 U.S.C. 793(c)(1)).

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . ." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111 (d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator ". . . shall, at least every 4 years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3.0 CHARACTERISTICS OF THE INDUSTRIAL BOILER SOURCE CATEGORY

3.1 GENERAL

In this section, industrial boilers are described and classified by type, fuel, and method of construction. The existing population of industrial boilers is characterized by design type and capacity. In addition, fuel usage patterns are discussed by EPA region, and boiler usage. Existing regulations applicable to industrial boilers are also presented.

3.1.1 Industrial Boiler Source Category

Industrial boilers are used in manufacturing, processing, mining, and refining industries to provide steam, hot water, and electricity. The industrial generation of electricity is quite limited, however, with the majority of industrial boiler fuel consumption dedicated to steam or hot water production. Between 10 and 15 percent of industrial boiler coal consumption and 5 to 10 percent of industrial boiler oil and gas consumption is used for electricity generation.[1]

Industrial boilers cover a broad range of sizes, with a few units as large as 200 MW (700 x 10^6 Btu/hr) thermal input. Some units are sufficiently small to allow shop fabrication and shipment as packaged boilers. When used for heating, they may have a steam pressure as low as 13.8 kPa (2 psi) and a temperature no higher than 375 K (215°F). Extremely large units, in contrast, may produce as much as 545 Mg/hr (1,200,000 lb/hr) of steam at a pressure of 12400 kPa (1800 psi) and a temperature of 811 K (1000°F).[2]

3.1.2 Classification of Industrial Boilers

Boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and, in the case of coal, the fuel feed system (pulverized or stoker). Pulverized coal-, oil-, and gas-fired boilers can be subclassified further by burner configuration (tangential, front wall or horizontally opposed). Most industrial boilers that are equipped with burners use the front wall configuration. For the purposes of this study, the burner-equipped boiler group will not be subclassified according to burner configuration.

Figure 3-1 illustrates a scheme for classifying boilers. According to this scheme boilers are first classified by the major distinguishing characteristic -- heat transfer mechanism -- into watertube, firetube, or cast iron design types. Watertube boilers can be either field-erected or shop-built packaged units, but essentially all firetube and cast iron units are packaged boilers. These boilers are further classified by fuel type. The fuel feed mechansim is an important characteristic affecting coal-fired boiler emissions. As shown on Figure 3-1, three types of stoker feeding mechanisms are used, in addition to pulverized coal systems. Differences in emissions and their potential for control exist among these boiler types due to the fuel fired and the mechanism for introducing that fuel (see Section 3.2 and Chapter 4).

3.1.2.1 Industrial Boiler Design Types. The three major boiler designs -- watertube, firetube, and cast iron -- are each manufactured to meet specific application and site requirements. Unit size, design steam pressure and temperature all depend on the application. Each of these boiler types may burn coal, oil, or gas and are increasingly being designed to burn more than one fuel type. Each of the three major design types are discussed in the following subsections.

3.1.2.1.1 Watertube boilers. Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. As the name implies, watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases. This process results in generation of high-pressure, high-temperature steam.

Watertube boilers are available, as packaged or field-erected units, in capacities ranging from less than 2.9 to over 200 MW (10 to 700 x 10^6 Btu/hr) thermal imput. As discussed in Section 3.2, industrial boilers

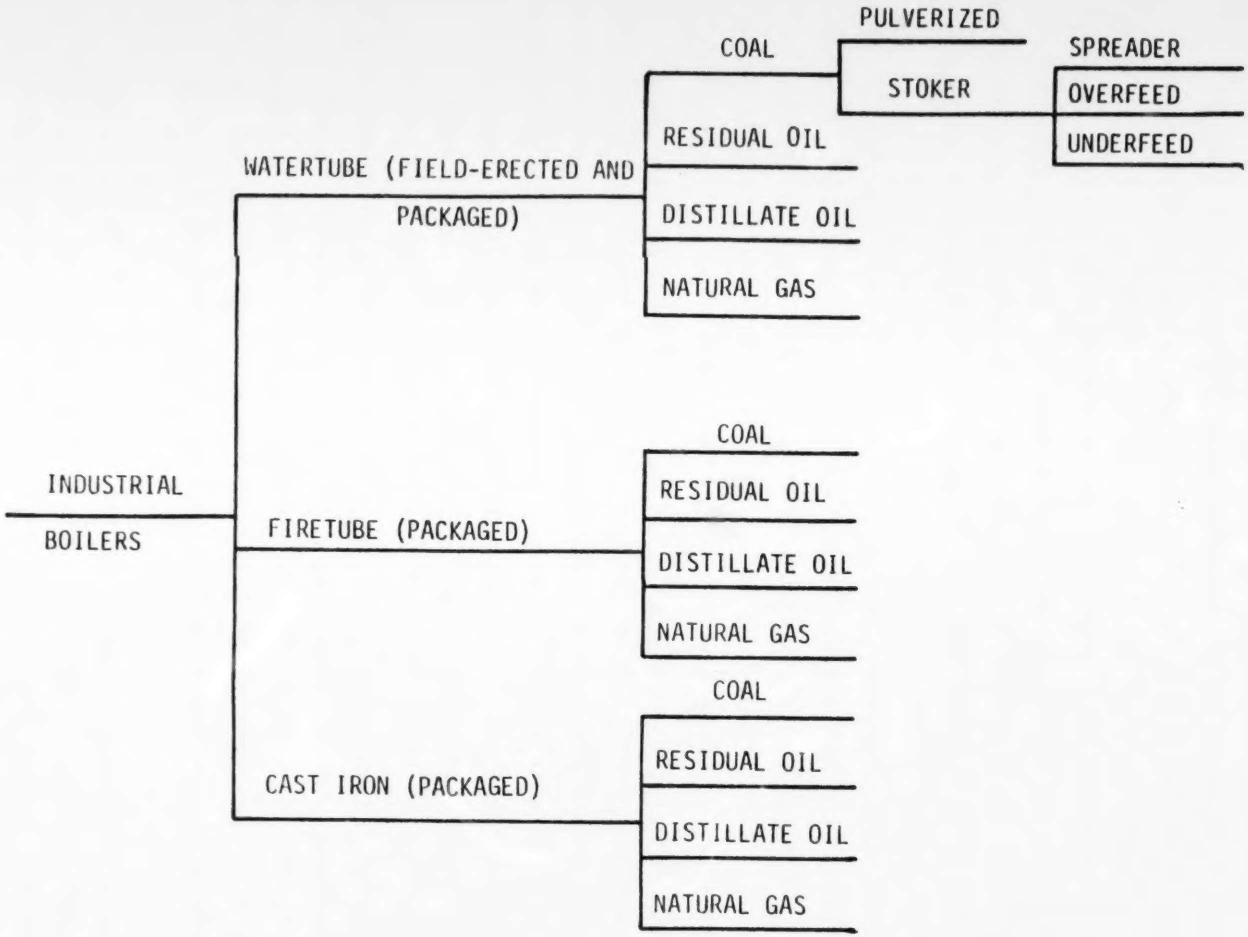

INDUSTRIAL
BOILERS
WATERTUBE (FIELD-ERECTED AND PACKAGED)
COAL
PULVERIZED
STOKER
SPREADER
OVERFEED
UNDERFEED
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS
FIRETUBE (PACKAGED)
COAL
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS
CAST IRON (PACKAGED)
COAL
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS

Figure 3-1. Categories of industrial boilers.

typically have a thermal efficiency of approximately 80 percent. Hence, the steam capacity range of these watertube units is less than 3.6 Mg/hr (8,000 lb/hr) to over 254 Mg/hr (560,000 lb/hr). Packaged boilers are generally smaller than the field-erected units. Virtually all units with a steam capacity of 4.5 to 45 Mg/hr (10,000 to 100,000 lb/hr) are packaged.[3] The maximum size of industrial packaged boilers is limited by transportability. Units up to 115 Mg/hr (250,000 lb/hr) of steam can be transported to operation sites by railroad, and larger ones can be moved by barge or freighter.

Industrial watertube boilers can burn coal, residual oil, distillate oil, natural gas, liquefied petroleum gas, and other fossil and nonfossil fuels. The packaged units, however, usually use premium quality fossil fuels -- oil and natural gas -- and do not offer the fuel flexibility that many buyers have recently desired.[4] More than half of the installed capacity of coal-fired industrial boilers are field-erected watertube models,[5] which are available as stoker or pulverized coal-fired units. A stoker is a conveying system that feeds coal into the furnace and also provides a grate upon which the coal is burned. In comparison, pulverized coal-fired units operate by using suspension burning. Coal pulverized to the consistency of powder is pneumatically injected into the furnace. Specific details of these boiler types are presented in Section 3.2.

3.1.2.1.2 Firetube boilers. Firetube boilers are used primarily for heating systems, industrial process steam, and portable power boilers.[6] Essentially all firetube boilers are packaged units with some being portable (or movable) rather than stationary. In firetube boilers, the hot gas flows through the tubes and the water being heated circulates outside of the tubes.

Firetube boilers are usually limited in size to 5.9 MW (20×10^6 Btu/hr) thermal input.[6] However, some firetube designs have been built with heat input up to 14 MW (50×10^6 Btu/hr). In general, firetube boilers offer the benefit of quick response to moderate load changes.[7] Most industrial firetube boilers currently available have tube arrangements that classify them as either horizontal return tube (HRT), firebox, or Scotch.

These tube arrangements are described in Section 3.2.3.2. Most of the installed capacity of firetube units is oil- and gas-fired.[8] Coal may play a more important role in the future, however.[3]

Boilers which are portable or semiportable are also used in industrial applications. Small boilers on wheels are used in a variety of industries for steam cleaning and pressing. Larger firetube units with complete piping and water supply systems may be mounted on trailers or flat beds and used for temporary heat or wall drying at construction sites. Portable or rental boilers do not differ in design from other package boilers but are typically provided with a very short stack.[9]

3.1.2.1.3 Cast iron boilers. In cast iron boilers, the hot gas is contained inside the tubes and the water being heated circulates outside the tubes. The units are constructed of cast iron rather than steel. Cast iron boilers are used to produce either low-pressure steam or hot water. Generally, boiler capacity ranges from 0.001 to 2.9 MW (0.003 to 10 x 10^6 Btu/hr)[10] thermal heat input with pressure ratings up to 690 kPa (100 psi) for hot water units and 100 kPa (15 psi) for steam units.[11] Thus, cast iron boilers are most commonly used in domestic or small commercial applications.[10]

3.1.2.2 Industrial Boiler Manufacturers. Tables 3-1 and 3-2 list manufacturers of industrial boilers. Manufacturers of watertube and firetube boilers are listed in Table 3-1. Most manufacturers of industrial watertube boilers make coal-fired units, but only a few of the firetube boiler manufacturers make coal-fired units. Establishments manufacturing cast iron boilers are listed in Table 3-2. According to the Hydronics Institute, which is the trade association for cast iron boiler manufacturers, only five firms produce units large enough for industrial applications.[12]

3.1.3 Population of Industrial Boilers

The installed population of industrial boilers is summarized by design type in Table 3-3. Figure 3-2 illustrates the relative distribution by capacity. As shown on this graph, watertube boilers are available over a larger size range than the other types. Note on Table 3-3 that nearly

Table 3-1. MANUFACTURERS OF INDUSTRIAL FIRETUBE AND WATERTUBE BOILERS[13]

Manufacturer	Firetubes		Watertubes		
	Oil & gas	Coal	Oil & gas	Coal	Upper size limit,[a] MW (10^6 Btu/hr) thermal input
ABCO Industries Abilene, TX	X		X		29 (100)
American Hydrotherm Corp. New York, NY			X		10 (35)
Babcock and Wilcox North Canton, OH			X	X	
Bettran Associates, Inc. Brooklyn, NY	X				
Bethlehem Corp. Easton, PA	X	X			
Bigelow Co. New Haven, CT	X		X	X	
Bryan Steam Corp. Peru, IN			X		6 (21)
Burham Corp. Lancaster, PA	X				
Clayton Manufacturing Co. El Monte, CA			X		6 (21)
Cleaver Brooks Milwaukee, WI	X		X		29 (100)
Combustion Engineering Windsor, CT			X	X	
Combustion Service & Equipment Co. Pittsburg, PA	X	X			
Delta Steel Boiler Industries Chicago, IL	X	X			
Deltak Minneapolis, MN				X	
Durham-Bush West Hartford, CT	X				

[a] Manufacturers of watertube boilers with no upper size limit listed produce units greater than 73 MW (250 x 10^6 Btu/hr) heat input.

Table 3-1 Continued. MANUFACTURERS OF INDUSTRIAL FIRETUBE AND WATERTUBE BOILERS[13]

	Firetubes		Watertubes		
Manufacturer	Oil & gas	Coal	Oil & gas	Coal	Upper size limit,[a] MW (10^6 Btu/hr) thermal input
Eclipse Lookout Co. Chattanooga, TN	X				
Foster-Wheeler Livingston, NJ			X	X	
Industrial Boiler Thomasville, GA	X	X			
Industrial Combustion, Inc. Milwaukee, WI	X				
International Boiler East Stroudsburg, PA			X	X	73 (250)
Johnston Boiler Co. Ferrysburg, MI	X	X			
E. Keeler Williamsport, PA			X	X	
Kewanee Boiler Corp. Kewanee, IL	X	X			
Kipper and Sons Engineers, Inc. Seattle, WA			X	X	
James Leffel Co. Springfield, OH	X	X			
Nebraska Boiler Co. Lincoln, NE	X		X	X	73 (250)
North American Manufacturing Co. Cleveland, OH	X	X			
Ocean Shore Boiler Works San Francisco, CA	X				
Oswego Package Boiler Oswego, NY	X				
Ray Burner Co. San Francisco, CA	X	X			

[a] Manufacturers of watertube boilers with no upper size limit listed produce units greater than 73 MW (250 x 10^6 Btu/hr) heat input.

Table 3-1 Concluded. MANUFACTURERS OF INDUSTRIAL FIRETUBE AND WATERTUBE BOILERS[13]

Manufacturer	Firetubes		Watertubes		
	Oil & gas	Coal	Oil & gas	Coal	Upper size limit,[a] MW (10^6 Btu/hr) thermal input
Riley Stoker Worcester, MA			X	X	
Seattle Boiler Works Seattle, WA	X		X		14 (50)
Sellers Engineering Co. Danville, KY	X				
Steamaster Automatic Boiler Co. Los Angeles, CA	X				
Struthers Wells Winfield, KS			X		29 (100)
Superior Boiler Works, Inc. Hutchinson, KS	X				
Thermo-Pak Boiler, Inc. Memphis, TN			X		6 (20)
Trane Company Lacrosse, WI	X		X		73 (250)
Vapor Division of Brunswick Corp. Chicago, IL			X		4 (15)
Henry Vogt Machine Company Louisville, KY			X	X	73 (250)
Williams and Davis Boiler and Welding Co., Inc. Hutchins, TX	X				
York-Shipley York, PA	X				
John Zink Tulsa, OK	X		X		73 (250)
Zurn Industries Erie, PA	X	X	X	X	

[a] Manufacturers of watertube boilers with no upper size limit listed produce units greater than 73 MW (250 x 10^6 Btu/hr) heat input.

TABLE 3-2. MANUFACTURERS OF INDUSTRIAL SIZE CAST IRON BOILERS[12]

Burnham Corporation
Lancaster, PA

Peerless Heater Company
Boyertown, PA

Slant/Fin Corporation
Greenvale, NY

H.B. Smith, Incorporated
Westfield, MA

Weil-McLain
Michigan City, IN

TABLE 3-3. BOILER POPULATION DISTRIBUTION BY HEAT - TRANSFER CONFIGURATION[7]

Heat-transfer configuration	Boiler Population		Total Boiler Capacity	
	Number of Boilers	Percent of Total	MW Thermal Input (10^6 Btu/hr)	Percent of Total
Watertube	37,969	7.5	638,665 (2.2×10^6)	70.0
Firetube	173,936	34.3	219,360 (7.6×10^5)	24.2
Cast iron	295,298	58.2	52,570 (1.8×10^5)	5.8

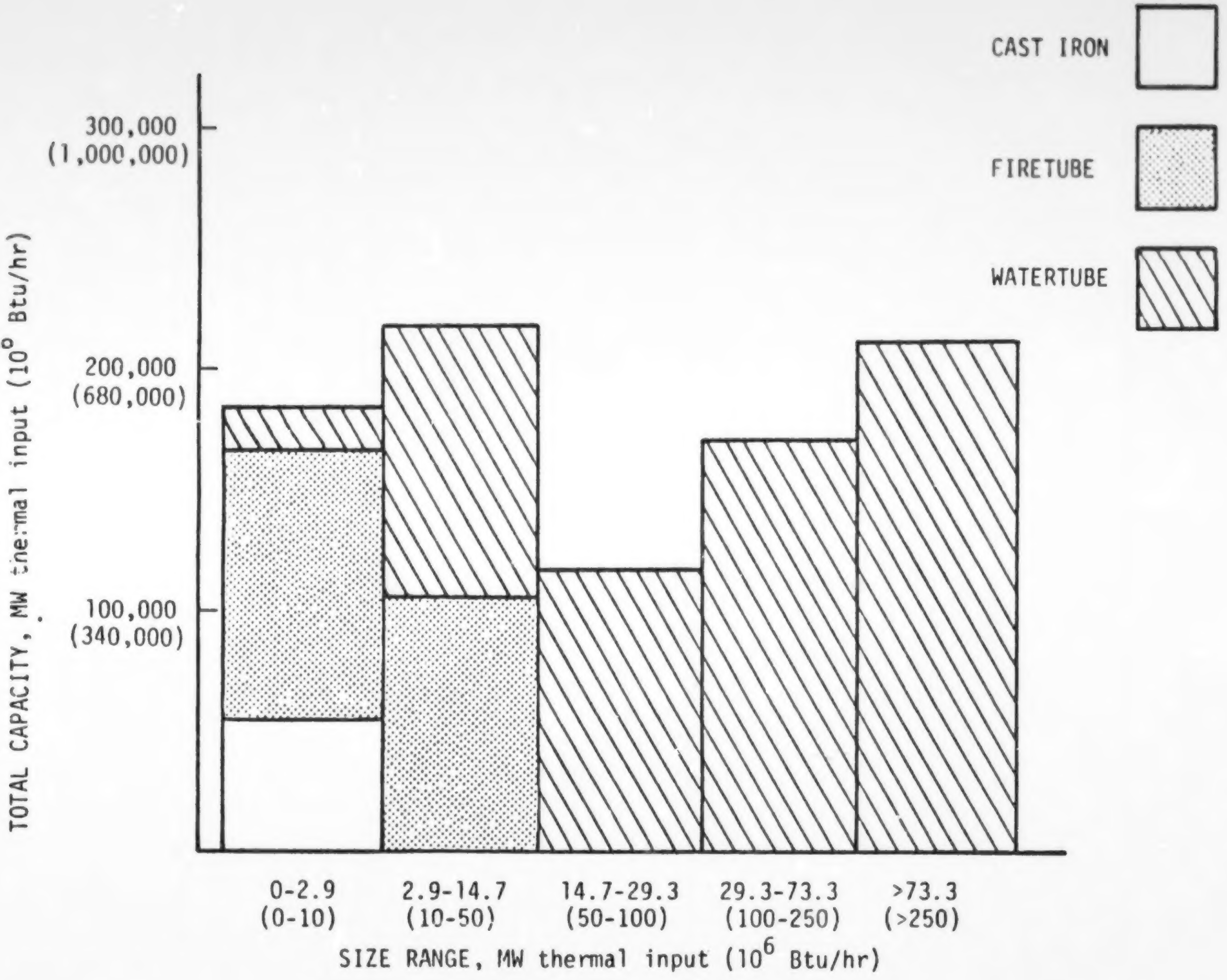


Figure 3-2. Relative distribution by capacity of the three types of industrial boilers.[5]

60 percent of the boilers are cast iron units, but these boilers account for only 6 percent of the installed capacity. Watertube boilers, on the other hand, represent 7 percent of the boilers by number, but account for 70 percent of the installed capacity. Figure 3-2 shows that the largest concentration of boiler capacity is in the 2.9 to 14.7 MW range, which contains 26 percent of the installed capacity. Units over 73.3 MW thermal input account for 23 percent, and those less than 2.9 MW thermal input account for 20 percent of the installed capacity.

Table 3-4 gives the distribution of watertube boilers by capacity and fuel. About 25 percent of the installed capacity is coal-fired, 32 percent is oil-fired, and 43 percent is natural gas-fired. This distribution varies with size. In the smallest size range (less than 2.9 MW thermal input), only 7 percent of the capacity is coal-fired, whereas in the largest boiler size group (above 73 MW thermal input), 30 percent of the installed capacity is coal-fired. Even in this large size group, however, 47 percent of the currently installed capacity is gas-fired.

Table 3-5 presents the distribution of firetube units, which range in size up to 14.7 MW (50 x 10^6 Btu/hr) thermal input. Only 6 percent of the installed capacity is coal-fired; 43 percent is oil-fired and 51 percent is natural gas-fired.

Cast iron boilers are the smallest of the three boiler types, with a maximum size of only 2.9 MW (10 x 10^6 Btu/hr) thermal input. In this group 12 percent of the installed capacity is coal-fired, 33 percent is oil-fired, and 55 percent is natural gas-fired, as shown in Table 3-6.

Information on the age distribution of existing industrial boilers was estimated by PEDCo Environmental, Inc. using sales data obtained from the American Boiler Manufacturers Association (ABMA) and the Hydronics Institute.[16] Based on these data, PEDCo stated that in 1978 about 20 percent of the watertube boiler capacity currently in place was less than 7 years old. (The sales data from ABMA were available for the previous 7 years.) About 25 percent of the current capacity of firetube and cast iron boilers is less than 10 years old. Further, based on discussions with boiler manufacturers, PEDCo estimated that 27 percent of the current sales

Table 3-4. INSTALLED CAPACITY OF U.S. WATERTUBE INDUSTRIAL BOILERS BY UNIT SIZE AND FUEL TYPE[14]

(MW thermal input (10^6 Btu/hr))

Fuel	Capacity by unit size 0 to 2.9 (0 to 10)	2.9 to 14.7 (10 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	>73.3 (>250)	Totals
Pulverized coal	0 (0)	0 (0)	0 (0)	19,895 (67,800)	40,180 (137,000)	60,075 (204,800)
Spreader-stoker coal	70 (240)	4,650 (15,900)	6,175 (21,060)	20,295 (69,000)	11,010 (37,600)	42,200 (143,800)
Underfeed-stoker coal	680 (2,300)	14,105 (48,000)	17,265 (58,900)	7,080 (24,200)	5,230 (17,800)	44,360 (151,200)
Overfeed-stoker coal	85 (290)	3,470 (11,800)	4,455 (15,200)	3,555 (12,100)	3,510 (12,000)	15,075 (51,390)
Total coal	835 (2,830)	22,225 (75,700)	27,895 (95,160)	50,825 (173,100)	59,930 (204,400)	161,710 (551,190)
Residual oil	3,960 (13,500)	48,190 (164,000)	35,640 (122,000)	44,790 (153,000)	43,570 (148,600)	176,150 (601,100)
Distillate oil	2,560 (8,700)	8,280 (28,200)	4,295 (14,600)	6,370 (21,700)	4,085 (13,900)	25,590 (87,100)
Total oil	6,520 (22,200)	56,470 (192,200)	39,935 (136,600)	51,160 (174,700)	47,655 (162,500)	201,740 (688,200)
Natural gas	4,475 (15,300)	57,900 (197,500)	53,585 (182,800)	63,320 (216,000)	95,935 (327,200)	275,215 (938,800)
Total all fuels	11,830 (40,330)	136,595 (465,400)	121,415 (414,560)	165,305 (563,800)	203,520 (694,100)	638,665 (2,178,190)

TABLE 3-5. INSTALLED CAPACITY OF INDUSTRIAL FIRETUBE BOILERS BY SIZE AND FUEL TYPE[8]

[MW thermal input (10^6 Btu/hr)]

Fuel	Capacity by unit size		
	0 to 2.9 (0 to 10)	2.9 to 14.7 (10 to 50)	Total
Coal	5,650 (19,270)	7,780 (26,530)	13,430 (45,800)
Residual oil	35,280 (120,330)	25,860 (88,200)	61,140 (208,530)
Distillate oil	17,770 (60,610)	15,770 (53,790)	33,540 (114,400)
Natural gas	59,120 (201,630)	52,130 (177,790)	111,250 (379,420)
Total	117,820 (401,840)	101,540 (346,310)	219,360 (748,150)

TABLE 3-6. INSTALLED CAPACITY OF INDUSTRIAL CAST IRON BOILERS BY FUEL TYPE[15]

[MW Thermal Input (10^6 Btu/hr)]

Fuel	Boiler Capacity[a]
Coal	6,330 (21,590)
Residual oil	10,780 (36,770)
Distillate oil	6,740 (22,990)
Natural gas	28,720 (97,950)

[a] All cast iron boilers have a capacity less than 4.0 MW thermal input (14 x 10^6 Btu/hr).

of watertube and firetube boilers and 50 percent of the sales of cast iron units are replacements for existing boilers that are being retired.[17]

Seasonal and time-of-day changes in energy demand result in excess capacity during nonpeak demand periods. Section 3.1.4 discusses these variations in capacity utilization by industry. Since capacity utilization varies widely in industry, the installed capacity by itself is not an adequate measure of fuel consumption. This information must be obtained from actual fuel usage data. Summaries of industrial fuel consumption data are presented in the next subsection.

3.1.4 Fuel Usage Patterns

Table 3-7 gives fossil fuel consumption by the manufacturing industries in each EPA region. Region V (including Ohio, Michigan, Illinois, and Indiana) is a heavy consumer of fossil fuels, using nearly 40 percent of the national annual coal consumption by manufacturers and about 20 percent of the U.S. annual consumption of distillate oil and natural gas by the manufacturing industries. Region VI (including Texas and Louisiana) consumes 40 percent of the natural gas. In general, the largest end use of each fuel in each region is for process steam, accounting for about one-third of the fuel used by industry nationwide.[19] Use of fuel as feedstock accounts for less than one-third of the manufacturing fuel use. Industrial process heating in furnaces and space heating accounts for most of the remaining industrial fuel consumption.[19]

Table 3-8 lists the percent of industrial boiler fossil fuel consumption by industry and fuel type for 1974. The most energy intensive industries--chemicals and paper--account for over one-third of the industrial boiler fuel consumption. The other industries listed (petroleum refining, steel, aluminum, and food) account for much of the remaining industrial boiler fuel consumption. Other industries, using smaller but significant amounts of fuel in boilers, include textiles, lumber, rubber, metal fabrication, and transportation.

Table 3-9 relates the share of fuel used in this country by industry to the quantities used by other sectors. In addition to manufacturing, the

TABLE 3-7. REGIONAL FOSSIL FUEL CONSUMPTION BY THE MANUFACTURING INDUSTRIES IN 1976[a]
[Exajoules (10^{15} Btu)]

EPA Region	Residual oil	Distillate oil	Coal	Natural gas	Total
I	0.19 (0.18)	0.033 (0.031)	0.0071 (0.0067)	0.081 (0.077)	0.31 (0.29)
II	0.21 (0.20)	0.077 (0.073)	0.20 (0.19)	0.18 (0.17)	0.67 (0.63)
III	0.28 (0.27)	0.12 (0.11)	1.2 (1.1)	0.51 (0.48)	2.1 (2.0)
IV	0.38 (0.36)	0.14 (0.13)	0.48 (0.45)	0.69 (0.65)	1.7 (1.6)
V	0.26 (0.25)	0.12 (0.11)	1.4 (1.3)	1.4 (1.3)	3.2 (3.0)
VI	0.09 (0.085)	0.039 (0.037)	0.079 (0.075)	2.7 (2.6)	2.9 (2.8)
VII	0.023 (0.022)	0.026 (0.025)	0.11 (0.1)	0.32 (0.3)	0.48 (0.45)
VIII	0.029 (0.027)	0.0095 (0.009)	0.10 (0.095)	0.14 (0.13)	0.28 (0.26)
IX	0.05 (0.047)	0.023 (0.022)	0.088 (0.083)	0.48 (0.46)	0.64 (0.61)
X	0.051 (0.048)	0.023 (0.022)	0.019 (0.018)	0.19 (0.18)	0.28 (0.27)
Total	1.6 (1.5)	0.61 (0.58)	3.7 (3.5)	6.7 (6.4)	13 (12)

[a] The fuel consumption data include use in process heaters and as feedstock as well as in boilers. Reference 18.

Table 3-8. DISTRIBUTION OF INDUSTRIAL BOILER FOSSIL FUEL CONSUMPTION IN 1974 BY INDUSTRY AND FUEL TYPE[20]

(percent)

Industry	Fuel type Coal, %	Oil, %	Gas, %	Total, %
Chemicals	4.5-5.6	1.9-2.4	14-17	20-25
Paper	2.9-3.6	6-7.4	4-5	13-16
Steel and aluminum	2.6-3.3	0.68-0.85	5.5-6.8	8.8-11
Food	1.1-1.3	1.3-1.6	4.8-5.9	7.1-8.8
Petroleum refining	0.07-0.09	1.2-1.5	3.8-4.8	5.1-6.4
Other manufacturing	3.5-4.3	6.1-8.5	14-35	24-48
Total	15-18	17-22	46-75	100

TABLE 3-9. UNITED STATES PRIMARY ENERGY CONSUMPTION BY CONSUMING SECTOR AND ENERGY SOURCE, 1974[2].

[Exajoules (10^{15} Btu)]

Consuming sector[a]	Coal	Petroleum	Natural gas	Nuclear	Hydropower and geothermal	Total	Percent
Household and commercial	0.31 (0.29)	6.75 (6.39)	7.51 (7.1)	--	--	14.6 (13.8)	18.9
Industrial[b]	4.44 (4.2)	6.38 (6.04)	11.75 (11.1)	--	--	22.6 (21.4)	29.3
Transportation	0.01 (0.01)	18.6 (17.6)	0.70 (0.66)	--	--	19.3 (18.3)	25.0
Electrical generation	9.15 (8.67)	3.64 (3.45)	3.51 (3.23)	1.24 (1.17)	3.19 (3.02)	20.7 (19.6)	26.8
Total	13.9 (13.2)	35.4 (33.5)	23.5 (22.2)	1.24 (1.17)	3.19 (3.02)	77.2 (73.1)	100.0
Percent	18.0	45.9	30.4	1.6	4.1	100.0	

[a] Excludes use of electrical energy by household, commercial, industrial, and transportation sectors

[b] Includes all manufacturing sectors.

industrial sector includes the mining, agricultural, and construction industries.

3.2 INDUSTRIAL BOILERS AND THEIR EMISSIONS

An overview of industrial boiler emissions is presented in this section. Representative boilers for each major class of boilers are selected and mass and energy balances are presented. These mass balances are based on emission factors for each fuel type. Finally, in conjunction with the mass balances and discussion of boiler types, factors affecting emissions for each boiler type are discussed.

This section begins with a qualitative discussion of uncontrolled industrial boiler emissions (Section 3.2.1). Following this overview are individual subsections dealing with emissions from various types of boilers. For purposes of this analysis, these subsections are arranged by fuel type with subsections for coal, oil, and natural gas (3.2.2, 3.2.3, and 3.2.4 respectively). At the conclusion of each subsection, emission factors (on a ng/J or lb/10^6 Btu heat input basis) are presented. These emission factors are used to quantify uncontrolled emissions throughout the remainder of this report.

Because cast iron boilers are small, less than 2.9 MW (10×10^6 Btu/hr) thermal imput, and most new boilers will be watertube or firetube types, cast iron boilers are not discussed in this section. In addition, fugitive emissions, which result from processes such as the transfer and storage of coal and oil supplies, and the preparation of the coal (grinding and pulverizing), are not considered.

3.2.1 Uncontrolled Emissions Overview

Emissions from industrial boilers include particulate matter (PM), sulfur oxides (SO_x), nitrogen oxides (NO_x), and lesser amounts of carbon monoxide (CO), hydrocarbons (HC), and trace elements. In the following subsections, sources of these pollutants are noted, and factors affecting their emission rates are discussed qualitatively.

3.2.1.1 Particulate Matter (PM) Emissions. Uncontrolled PM emissions from coal-fired boilers include the ash in the fuel as well as unburned carbon resulting from incomplete combustion. Emission factors for PM are normally expressed as a function of fuel ash content for coal-fired boilers (see Section 3.2.2). Coal ash may either settle out in the boiler (bottom ash) or be carried out with the flue gas (fly ash). The distribution of ash between the bottom and flyash fractions directly affects the PM emissions rate[22] and is a function of the following:

- Boiler firing method -- The type of firing is perhaps the most important factor in determining ash distribution. For example, stoker-fired units emit less fly ash than dry bottom, pulverized-coal-fired boilers.
- Wet or dry bottom furnace -- Furnaces which are designed to generate a dry bottom ash entrain PM from the bottom ash hopper into the flue gas stream more easily than do boilers whose bottom ash is in the molten state.

Boiler load also affects PM emissions from coal-fired boilers. In general, decreasing load tends to reduce PM emissions, however, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

For oil-fired boilers, carbon residue, a measure of the heaviest and least volatile components in the oil[23], is the most important fuel property influencing PM emissions of size greater than 10 μm. The PM emitted by distillate oil-fired boilers is primarily carbonaceous particles resulting from the partial combustion of the fuel. PM emissions from distillate oil-fired boilers do not correlate with the ash or sulfur content of the fuel.[24] Unlike the emissions from coal-fired boilers, the PM emissions from distillate oil-fired boilers do not necessarily vary with boiler load in a general trend.[25]

Residual oil-fired boiler PM emissions result from ash in the fuel as well as incomplete combustion of the fuel. Test data reported in AP-42 shows PM emissions from residual oil-fired units vary with the sulfur content of the fuel.[26] Thus emission factors for PM, which are presented later, are expressed as a function of sulfur content for residual oil-fired units. PM emissions from residual oil-fired boilers are influenced by boiler load and tend to decrease with decreasing load.

The PM emission factors for industrial boilers firing natural gas are very low because natural gas has little or no ash content and combustion is more complete than with other fuels.

Soot blowing is another source of PM emissions in coal- and residual oil-fired boilers. Steam soot blowing is used intermittently in industrial boilers to dislodge ash from heat transfer surfaces in the boiler furnace, convection section, and economizer/preheater. On small boilers with single soot blowers, soot blowing may only take place for a few seconds once a shift. Large industrial boilers may have numerous soot blowers installed and operated in a cycle which may approach "continuous" soot blowing. The incremental PM emissions associated with soot blowing are not reflected in AP-42 emission factors and boiler owners and equipment vendors disagree as to whether or how emissions resulting from soot blowing are accounted for in the design of industrial boiler PM emission control equipment.[27] Test data reported in Chapter 4 show varied impacts of soot blowing on controlled emissions depending on the type of emission control technique employed. In general, soot blowing appears to have only a small effect on opacity with opacity increases of less than 5 percentage points.[28]

3.2.1.2 Sulfur Oxide Emissions. SO_2 emissions are generated in industrial boilers due to oxidation of sulfur contained in fuels. SO_x emissions from industrial boilers are predominantly in the form of SO_2; SO_3 emissions account for only 1 or 2 percent of the total SO_x emissions. Uncontrolled emissions of SO_2 depend directly on the sulfur content of the fuel. The type of firing mechanism does not affect SO_2 emissions, but variations in fuel properties do.[29] Therefore, a different emission factor, that is primarily a function of the amount of sulfur in the fuel, is used for each fuel type. This factor is essentially constant for all boiler types firing the same fuel.

The emission factor in AP-42 for coal-fired units assumes that less than 5 percent of the sulfur in the coal is emitted with the particulate matter or retained by the bottom ash. The amount of sulfur retained by the fly ash and bottom ash appears to be a function of ash composition, related to the alkalinity of the ash.[30] Combustion of highly alkaline Western subbituminous coals can result in 20 percent of the sulfur in the coal being emitted with the fly ash or retained in the bottom ash.[31] Thus, the SO_2 emission factor for coal is based on an average of emissions from many coal types, and variations from this average will occur.

3.2.1.3 Nitrogen Oxide Emissions. Oxides of nitrogen (including NO and NO_2) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air, resulting in formation of thermal NO_x, or to the conversion of chemically bound nitrogen in the fuel, resulting in formation of fuel NO_x. For natural gas and distillate oil firing, nearly all NO_x emissions are thermal NO_x. With residual oil and coal fuels, the contribution from fuel NO_x can be significant and even predominant.[32]

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature and also proportional to the N_2 concentration, the residence time, and the square root of O_2 concentration at the flame.[33] Thus, the formation of thermal NO_x is affected by four factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly consistent for all types of boilers; an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production regardless of the boiler type.

As mentioned previously, fuel NO_x is of importance for residual oil and coal firing. It can account for 50 percent of the total NO_x emissions in residual oil firing and for 80 percent in coal firing.[34] The percent conversion of fuel nitrogen to NO_x, however, varies greatly. Anywhere from 20 to 90 percent of nitrogen in oil is converted to NO_x while the percentage of nitrogen in coal converted to NO_x ranges from 5 to 60 percent.[35] Furthermore, test data indicate that the percent of fuel nitrogen conversion decreases as the fuel nitrogen content increases. An average conversion of

46 percent was found for residual oil, and nearly 100 percent for distillate oil.[35] For coal-fired units the fuel nitrogen conversion varies depending on the combustion conditions present with the particular boiler and fuel (see Section 4.3).

3.2.1.4 Carbon Monoxide Emissions. The rate of CO emissions from boilers depends on the efficiency of the combustion of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. The effects of combustion modifications for purpose of NO_x control on uncontrolled CO and HC emissions are discussed in Section 4.3 of this document.

3.2.1.5 Hydrocarbon Emissions. The rate of HC emission from boilers also depends on the combustion efficiency. Hydrocarbon emissions are minimized by use of proper combustion practices. Fuel type also affects HC emissions. Liquid and gaseous fuels have better mixing and firing characteristics than solid fuels, accounting in part for the lower hydrocarbon emissions for oil and natural gas-fired units than for comparable coal units.

3.2.1.6 Trace Element Emissions. Trace elements are found in fossil fuels, especially in coal and residual oil. Smaller concentrations of trace elements are also found in distillate oil, but virtually none are found in natural gas.

Trace elements can be classified according to the way they are emitted during the combustion process: (1) distributed between bottom ash and fly ash, (2) concentrated in fly ash, especially the fine particulate in the flue gas; or (3) as vapors. Trace elements that do not vaporize during fuel combustion are emitted in about equal concentration in bottom ash and fly ash particles. Those with lower boiling points, which vaporize during combustion, become concentrated in fly ash and are carried out by the flue gas. Some trace elements, such as mercury, are emitted through the stack into the atmosphere as vapors. Others, such as arsenic, cadmium, copper, lead, tin, and zinc, condense on fly ash particles and are emitted with them into the atmosphere.[36]

The quantity of trace elements actually emitted depends on three factors:

- combustion temperature,
- fuel analysis and feed mechanism, and
- characteristics of the flue gas.

The fuel analysis determines the quantity of trace elements present. The combustion temperature determines the degree of volatilization for specific trace elements, and the fuel feed mechanism influences the partitioning of non-combustible substances between bottom ash and fly ash. The temperature of the flue gas affects the relative amounts of volatile trace elements which are emitted condensed on fly ash particles compared to being emitted as vapors.

3.2.2 Coal-fired Boilers

The different types of coal-fired boilers are described in this section and uncontrolled emission factors for each boiler type are discussed. Mass and energy balances are presented for representative boilers. The mass and energy balances were developed from the combustion and flue gas information developed by Devitt, et al.[37] The combustion information considered includes fuel rates, excess air percentages, and fuel analysis.

The fuel input rate was computed from the specified heat input rate and fuel heating value, while the theoretical (no excess air) combustion air requirement per unit mass of fuel burned was calculated from the fuel analysis. The actual mass rate of combustion air supplied to the boiler was then determined from the fuel input rate and a specified excess air percentage. Pollutant emission rates were computed from the emission factors, the heat input rate, and the fuel ash and/or sulfur content, as appropriate. The bottom ash discharge rate was taken to be the difference between the ash input rate (from the fuel analysis and fuel input rate) and the fly ash emission rate. The flue gas rate was then calculated by subtracting all the mass emission and discharge rates from the sum of fuel and total combustion air mass input rates.

For all of the coal-fired units, a high sulfur, high-ash coal was used as the fuel to develop the mass balances. The ultimate analysis of this coal, along with a representative low-sulfur, low-ash coal, is presented in Table 3-10.

Similarly, energy balances were calculated using boiler heat input rates and typical efficiencies provided by Devitt, et al.[37] Boiler energy losses which include the flue gas losses and boiler radiative and convective losses were combined and treated as one "loss" term.

All coal-fired industrial boilers have common characteristics. Coal storage and handling are necessary at the boiler site to ensure that an adequate supply of fuel is on hand and that the fuel is ready for combustion. For pulverized coal-fired units, this involves crushing and grinding the coal to the proper consistency, and for stoker units it involves crushing and screening the coal to acceptable size. Coal-fired units require ignition with either oil or gas, and many are designed to fire oil or natural gas as a backup fuel.

Excess air is necessary for proper combustion, but too much can be detrimental to the performance of the combustion system. The detrimental effects of too much combustion air include:

- Reducing combustion temperatures and retarding the combustion rate;
- Reducing thermal efficiency, thus requiring more fuel for a given steam output; and
- Increasing gas velocities in the furnace causing transport of fuel particles out of the furnace before complete combustion.

The effects of too much combustion air on uncontrolled PM emissions are most significant if it is injected as undergrate air. Increasing undergrate air directly affects the upward furnace gas velocities and increases fuel and particle entrainment.

As mentioned earlier, cast iron industrial boiler emissions are not examined because of the small size and minimal installed capacity of cast iron units. The emissions from the remaining two types of coal-fired industrial boilers, watertube and firetube, are discussed in the following

Table 3-10. ULTIMATE ANALYSIS OF COAL SELECTED FOR THE REPRESENTATIVE BOILERS[38]

Fuel	Composition, percent by weight							Heating value, kJ/kg (Btu/lb)
	Water	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
High-sulfur, high-ash coal	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,447 (11,800)
Low-sulfur, low-ash coal	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

subsections. Following these two subsections, emission factors for coal-fired boilers are presented.

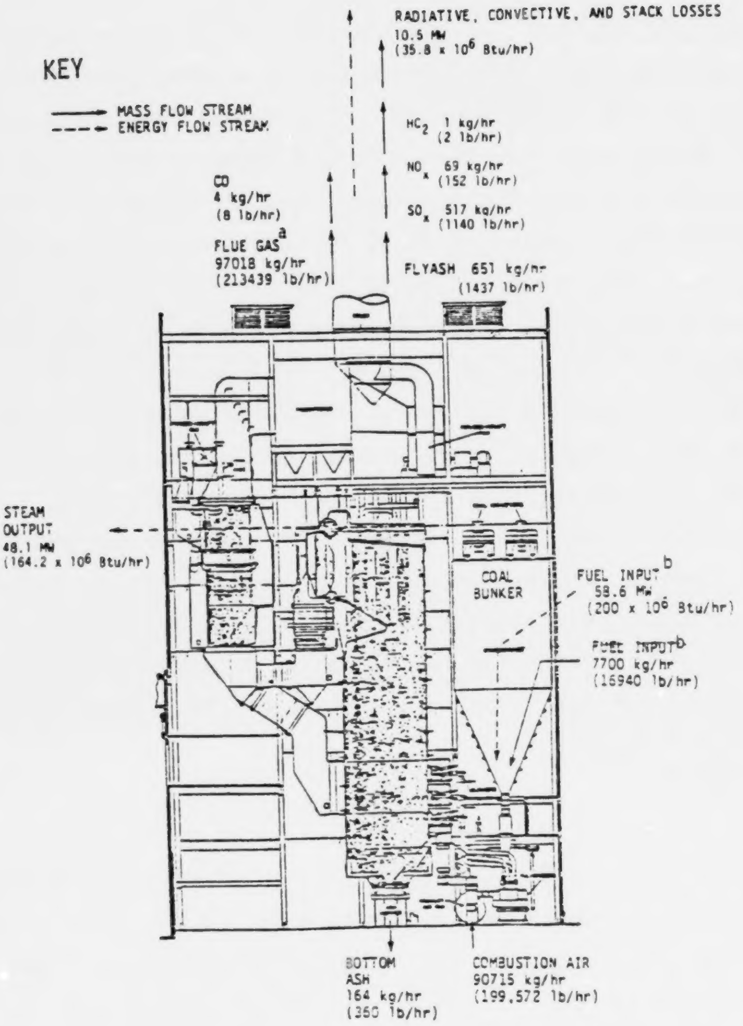
3.2.2.1 Watertube Boilers. A watertube boiler is one in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes. The tubes are interconnected to common water channels and to a steam outlet or outlets.

Watertube boilers can generate high-pressure, high-temperature steam, up to 12,000 kPa (1740 psi) and 810 K ($1000^{o}F$), and are available in many sizes (see Table 3-4). The tubes are of relatively small diameter, 5 cm (2.0 inch), providing rapid heat transfer, good response to steam demands, and high efficiency.[39]

There are two main types of coal-fired watertube boilers: pulverized coal and stoker-fired. Industrial size pulverized coal units range from 29.3 MW to over 200 MW (100 to 700 x 10^6 Btu/hr) heat input,[14] and burn the coal in suspension. A stoker is a conveying system that serves both to feed the coal into the furnace and to provide a grate upon which the coal is burned. Since feed rates by stoker units are limited, stokers are generally used on units rated at less than 117 MW (400 x 10^6 Btu/hr) heat input.[14] The three main types of stoker furnaces are spreader, overfeed or chain-grate, and underfeed.

Pulverized Coal-Fired

In pulverized coal-fired boilers the fuel is pulverized to the consistency of light powder and pneumatically injected through the burners into the furnace. Combustion begins at the burners and continues into the furnace volume. Wet-bottom furnaces are designed to operate at high temperatures and therefore keep the ash in the molten state until it collects in the bottom ash hopper. Dry-bottom furnaces, on the other hand, operate at lower combustion temperatures; consequently, the bottom ash remains in the solid state. Wet-bottom units are not expected to be manufactured and sold in the future.[40] Figure 3-3 illustrates a typical 58.6 MW (200 x 10^6 Btu/hr) heat input, dry-bottom pulverized coal unit with the corresponding mass and energy balances. Thirty percent excess air and a


RADIATIVE, CONVECTIVE, AND STACK LOSSES
10.5 MW
(35.8 x 10^6 Btu/hr)
KEY
MASS FLOW STREAM
ENERGY FLOW STREAM
HC2 1 kg/hr
(2 lb/hr)
NOx 69 kg/hr
(152 lb/hr)
CO
4 kg/hr
(8 lb/hr)
SOx 517 kg/hr
(1140 lb/hr)
FLUE GAS[a]
97018 kg/hr
(213439 lb/hr)
FLYASH 651 kg/hr
(1437 lb/hr)
STEAM
OUTPUT
48.1 MW
(164.2 x 10^6 Btu/hr)
COAL
BUNKER
FUEL INPUT[b]
58.6 MW
(200 x 10^6 Btu/hr)
FUEL INPUT[b]
7700 kg/hr
(16940 lb/hr)
BOTTOM
ASH
164 kg/hr
(360 lb/hr)
COMBUSTION AIR
90715 kg/hr
(199,572 lb/hr)

[a] Flue gas is defined here as major components only (H_2O, CO_2, O_2, N_2).
[b] Fuel is high sulfur eastern coal.

Figure 3-3. Mass and energy balances for a 58.6 MW (200 x 10^6 Btu/hr) pulverized coal-fired boiler.[41]

boiler efficiency of 82.1 percent were used to compute the mass and energy balances.[42]

Spreader Stoker

The spreader stoker combines suspension burning and a thin, fast-burning fuel bed on a grate. The modern spreader stoker, as shown in Figure 3-4, consists of feeder units (arranged to distribute fuel over the grate area), a grate (which may be stationary or moving), forced-draft systems for both undergrate and overgrate air, and combustion controls to coordinate air and fuel supply.

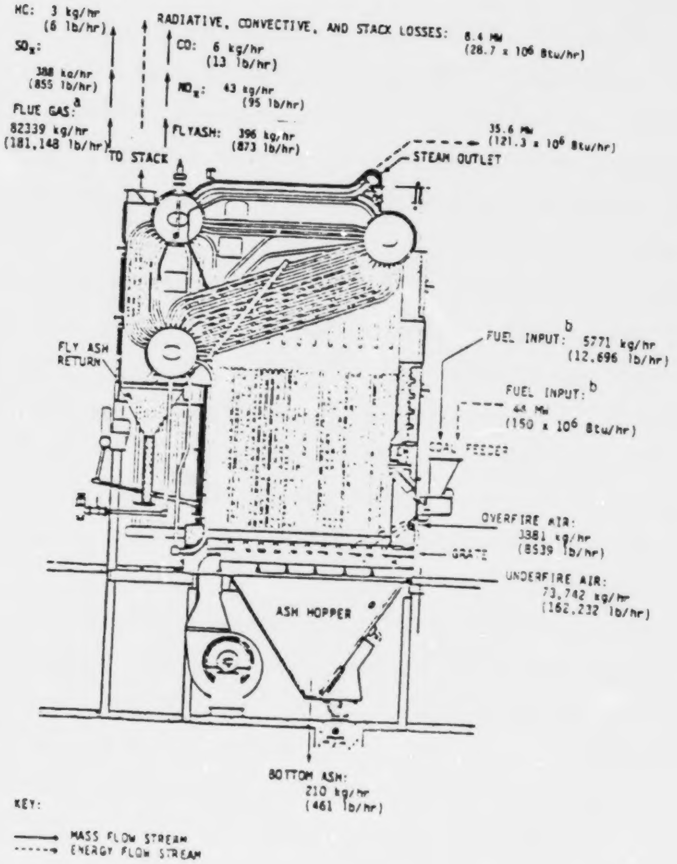
Some spreader stokers use a fly ash reinjection system, where the fly ash removed in a downstream control device is reinjected into the boiler. This technique tends to increase carbon utilization and boiler efficiency (up to 2-3 percent).[43] However, it also increases corrosion and slagging in the boiler and increases uncontrolled PM emissions. Fly ash reinjection was quite popular 10 years ago, but recent boiler designs have increased carbon utilization to the point where the advantages no longer outweigh the disadvantages in new units.[40]

Traveling-grate spreader stokers are generally installed with one large plenum or air chamber under the entire grate surface. Overfire air systems are useful in promoting good combustion and reducing the formation of smoke, especially for lower loading rates. The spreader stoker boiler shown in Figure 3-4 has a capacity of 44 MW (150 x 10^6 Btu/hr) heat input. The mass and energy balance is based on an overall boiler thermal efficiency of 81 percent and 50 percent excess air, including 5 percent overfire air.[44]

Overfeed (Chaingrate) Stoker

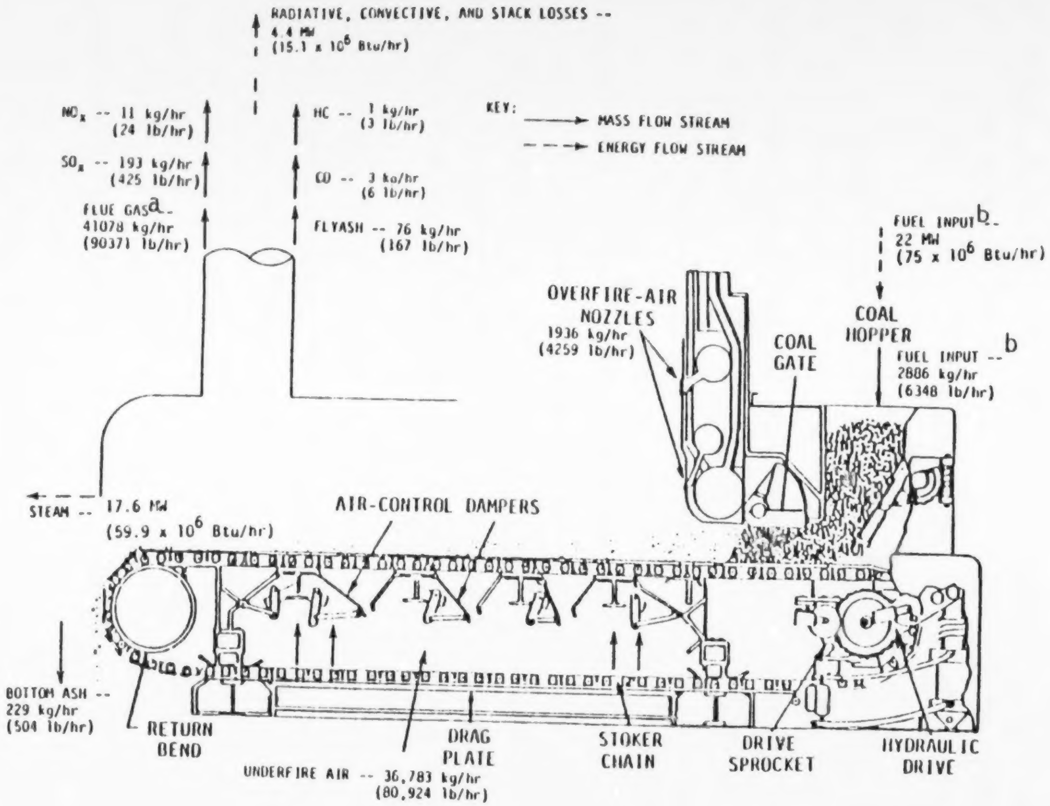
Overfeed stokers are generally equipped with chain or moving grates. In addition, they have refractory arches or overfire air jets to improve combustion. This type of stoker is now usually designed for forced draft operation; natural draft designs are gradually becoming obsolete. Chaingrate stokers are generally less than 73.3 MW (250 x 10^6 Btu/hr) heat input.[14]

As shown in Figure 3-5, coal is fed from a hopper onto a moving grate and enters the furnace after passing under an adjustable grate that


HC: 3 kg/hr
(6 lb/hr)
SO$_x$:
388 kg/hr
(855 lb/hr)
FLUE GAS:[a]
82339 kg/hr
(181,148 lb/hr)
TO STACK
RADIATIVE, CONVECTIVE, AND STACK LOSSES: 8.4 MW
(28.7 x 10^6 Btu/hr)
CO: 6 kg/hr
(13 lb/hr)
NO$_x$: 43 kg/hr
(95 lb/hr)
FLYASH: 396 kg/hr
(873 lb/hr)
35.6 MW
(121.3 x 10^6 Btu/hr)
STEAM OUTLET
FLY ASH RETURN
FUEL INPUT:[b] 5771 kg/hr
(12,696 lb/hr)
FUEL INPUT:[b]
44 MW
(150 x 10^6 Btu/hr)
COAL FEEDER
OVERFIRE AIR:
3381 kg/hr
(8539 lb/hr)
GRATE
UNDERFIRE AIR:
73,742 kg/hr
(162,232 lb/hr)
ASH HOPPER
BOTTOM ASH:
210 kg/hr
(461 lb/hr)
KEY:
MASS FLOW STREAM
ENERGY FLOW STREAM

[a] Flue gas is defined in this figure as major components (CO_2, H_2O, N_2, O_2).
[b] Fuel is high sulfur eastern coal.

Figure 3-4. Mass and energy balances for 44 MW (150 x 10^6 Btu/hr) coal-fired spreader stoker.[45]


RADIATIVE, CONVECTIVE, AND STACK LOSSES --
4.4 MW
(15.1 x 10^6 Btu/hr)
NO_x -- 11 kg/hr
(24 lb/hr)
SO_x -- 193 kg/hr
(425 lb/hr)
FLUE GAS^a --
41078 kg/hr
(90371 lb/hr)
HC -- 1 kg/hr
(3 lb/hr)
CO -- 3 kg/hr
(6 lb/hr)
FLYASH -- 76 kg/hr
(167 lb/hr)
KEY:
MASS FLOW STREAM
ENERGY FLOW STREAM
FUEL INPUT^b --
22 MW
(75 x 10^6 Btu/hr)
COAL HOPPER
FUEL INPUT --^b
2806 kg/hr
(6348 lb/hr)
OVERFIRE-AIR NOZZLES
1936 kg/hr
(4259 lb/hr)
COAL GATE
STEAM -- 17.6 MW
(59.9 x 10^6 Btu/hr)
AIR-CONTROL DAMPERS
BOTTOM ASH --
229 kg/hr
(504 lb/hr)
RETURN BEND
DRAG PLATE
UNDERFIRE AIR -- 36,783 kg/hr
(80,924 lb/hr)
STOKER CHAIN
DRIVE SPROCKET
HYDRAULIC DRIVE

[a] Flue gas is defined in this figure as major components (CO_2, H_2O, N_2, O_2).
[b] Fuel is high sulfur eastern coal.

Figure 3-5. Mass and energy balances for a 22 MW (75×10^6 Btu/hr) coal-fired chaingrate stoker.[47]

regulates the thickness of the fuel bed. Combustion is completed by the time the coal reaches the far end of the grate, and the remaining ash is discharged into the ashpit.

Figure 3-5 shows a mass and energy balance for a typical 22 MW (75×10^6 Btu/hr) heat input chaingrate stoker. The calculations are based on 80 percent efficiency and 50 percent excess air, with overfire air accounting for 5 percent of the total combustion air.[46]

Underfeed Stoker

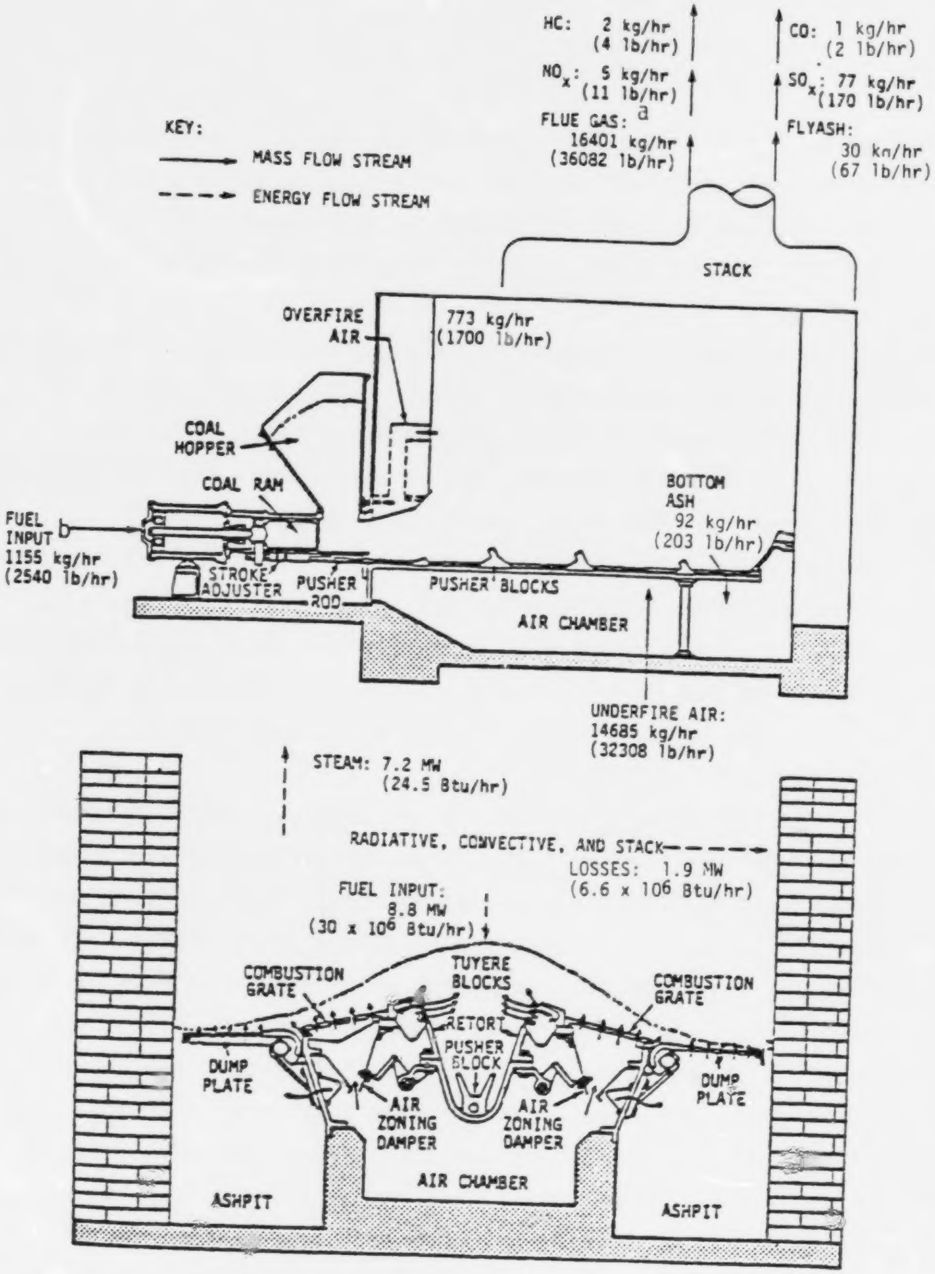
Various types of underfeed stokers are used in industrial boiler applications. They vary depending on whether the coal is fed horizontally or by gravity, whether the ash is discharged from the end or the sides, and how many retorts, or channels through which the coal is fed, are contained in the boilers. Underfeed stokers can burn a wide range of coals, including caking coals and anthracite.

In the side-discharge, horizontal underfeed stoker shown in Figure 3-6, coal is fed intermittently to the fuel bed by a ram. In very small units, the coal is fed continuously by a screw. The coal moves in a retort, and air is supplied through tuyeres on each side and through openings in the side grates. Single or double retort units are generally less than 73 MW (250×10^6 Btu/hr) heat input.

Overfire air is commonly used with underfeed stokers to provide some combustion air and turbulence in the flame zone directly above the active fuel bed. The air is provided by a separate overfire-air fan and is injected through small nozzles in the furnace walls.

An efficiency of 78 percent, a heat input of 8.8 MW (30×10^6 Btu/hr), and 50 percent excess air was used for the material and energy balances on this boiler.[49] Overfire air accounted for 5 percent of the total combustion air.

3.2.2.2 Firetube Boilers. In firetube boilers, the products of combustion flow through tubes that are surrounded by water. These units range in size from 0.1 to 5.9 MW (3.0 to 20×10^6 Btu/hr) thermal input and are used primarily for heating systems, to produce industrial process steam, and as portable power boilers.[6]


HC: 2 kg/hr (4 lb/hr)
CO: 1 kg/hr (2 lb/hr)
NO_x: 5 kg/hr (11 lb/hr)
SO_x: 77 kg/hr (170 lb/hr)
FLUE GAS:[a] 16401 kg/hr (36082 lb/hr)
FLYASH: 30 kg/hr (67 lb/hr)
KEY:
MASS FLOW STREAM
ENERGY FLOW STREAM
STACK
OVERFIRE AIR
773 kg/hr (1700 lb/hr)
COAL HOPPER
COAL RAM
FUEL INPUT[b] 1155 kg/hr (2540 lb/hr)
STROKE ADJUSTER
PUSHER ROD
PUSHER BLOCKS
BOTTOM ASH 92 kg/hr (203 lb/hr)
AIR CHAMBER
UNDERFIRE AIR: 14685 kg/hr (32308 lb/hr)
STEAM: 7.2 MW (24.5 Btu/hr)
RADIATIVE, CONVECTIVE, AND STACK LOSSES: 1.9 MW (6.6 x 10^6 Btu/hr)
FUEL INPUT: 8.8 MW (30 x 10^6 Btu/hr)
COMBUSTION GRATE
TUYERE BLOCKS
COMBUSTION GRATE
RETORT
PUSHER BLOCK
DUMP PLATE
AIR ZONING DAMPER
AIR ZONING DAMPER
DUMP PLATE
AIR CHAMBER
ASHPIT
ASHPIT

[a] Flue gas is defined here as major components only (H_2O, CO_2, O_2, N_2).
[b] Fuel is high sulfur eastern coal.

Figure 3-6. Mass and energy balances for an 8.8 MW (30×10^6 Btu/hr) underfeed stoker.[48]

Firetube boilers are generally used where steam/hot water demand can be maintained relatively constant because they are susceptible to structural failure when subjected to large variations in steam demand.[50] Over 90 percent of the installed capacity of firetube boilers is oil- or gas-fired.[51]

Six different types of firetube boiler configurations are commonly used. They include horizontal return tubular (HRT), Scotch marine, vertical, locomotive, short firebox, and compact boilers. The three configurations used most are the HRT, Scotch marine, and vertical units, while the most common firing mechanism is the underfeed stoker.

The feed and burner types differ between coal-fired and oil-fired units for each of the boilers. Scotch marine and HRT boilers are fired by all types of fossil fuel, but firing with coal requires increased maintenance to overcome scaling and slagging.[52] Since the majority of firetube boilers burn oil or gas, this type of boiler will be discussed further in Section 3.2.3 on oil-fired boiler emissions.

3.2.2.3 Emission factors for coal-fired boilers. Table 3-11 presents emission factors for the various types of pulverized and stoker coal-fired watertube industrial boilers discussed previously. These factors were taken from the U.S. EPA's compilation of Air Pollution Emission Factors (AP-42),[26] except for the NO_x emissions from underfeed and overfeed stokers which came from Reference 53, and the trace element emission factors, which were taken from Reference 54. The factors in Table 3-11 will be used throughout this study to represent uncontrolled emissions from industrial watertube boilers.

AP-42 lists no emission factors for coal-fired firetube boilers. Statistically reliable data on emissions from firetube boilers are not available, as only limited testing has been performed. The factors presented in Table 3-12 are based on two tests on a 3.2 MW (11×10^6 Btu/hr) heat input, underfeed stoker of unspecified tube configuration. These small units have higher CO emissions than watertube boilers but approximately the same NO_x and particulate emissions as underfeed watertube stokers.

As noted earlier, uncontrolled PM emissions from coal-fired boilers depend primarily on fuel ash content, firing mechanism, and boiler load.

TABLE 3-11. UNCONTROLLED EMISSION FACTORS FOR COAL-FIRED WATERTUBE INDUSTRIAL BOILERS[a]

[ng/J (lb/10^6 Btu)]

Pollutant	Underfeed Stokers 2.93 - 29.3 MW (10-100 x 10^6 Btu/hr)	Chaingrate Stokers 2.93 - 29.3 MW (10-100 x 10^6 Btu/hr)	Spreader Stokers 2.93 - 73.3 MW (10-250 x 10^6 Btu/hr)	Pulverized Coal 29.3 MW (100 x 10^6 Btu/hr)
Particulate Matter (PM)[b]	91.2 A (0.212 A)	91.2 A (0.212 A)	237 A[d] (0.551 A)	292 A (0.678 A)
Sulfur Dioxide (SO_2)[c]	693 S (1.61 S)	693 S (1.61 S)	693 S (1.61 S)	693 S (1.61 S)
Nitrogen Oxides (NO_x)	150 (0.349)	140 (0.326)	274 (0.636)	274 (0.763)
Carbon Monoxide (CO)	182 (0.424)	182 (0.424)	36.5 (0.0848)	18.2 (0.0424)
Hydrocarbons (HC)	54.6 (0.127)	54.6 (0.127)	18.2 (0.0424)	5.46 (0.0127)
Arsenic	3.4 (0.0079)	3.4 (0.0079)	3.4 (0.0079)	3.4 (0.0079)
Lead	3.7 (0.0086)	3.7 (0.0086)	3.7 (0.0086)	3.7 (0.0086)
Cadmium	0.20 (0.00046)	0.20 (0.00046)	0.20 (0.00046)	0.20 (0.00046)

[a] Sources - Reference 26 for PM, SO_2, NO_x, CO, and HC except, Reference 62 for NO_x from underfeed and chaingrate stokers, and Reference 78 for arsenic, lead, and cadmium.

Reference 26 expresses emissions on a lb/ton fuel burned basis. A conversion factor of 27,477 kJ/kg (11,800 Btu/lb) was used to convert factors to a heat input basis. Emission factors should be adjusted for fuels with heating values different from this value.

[b] A is the weight percent ash in coal.

[c] S is the weight percent sulfur in the coal.

[d] Flyash reinjection increases PM emissions by 1.54.

TABLE 3-12. UNCONTROLLED EMISSION FACTORS FOR COAL-FIRED UNDERFEED STOKER FIRETUBE INDUSTRIAL BOILERS[54]

Pollutant	Emission factors, ng/J (lb/10^6 Btu)
Particulates[a]	50A (0.12A)
Sulfur oxides[b]	692S (1.61S)
Nitrogen oxides	177 (0.41)
Carbon monoxide	261 (0.61)
Hydrocarbons	c

[a] A is the ash content of the fuel in weight percentage. this emission factor is based on a coal with a heat content of 27,447 kJ/kg. It must be adjusted for coals with different heat content.

[b] S is the sulfur content of the fuel in weight percentage.

[c] No factor available.

Stokers generally have lower PM emissions than pulverized coal-fired units because the coal is burned on a bed, which leads to less entrainment of PM than suspension burning. PM emission rates for spreader stokers are higher than they are for the other two stoker types because partial burning of the fuel in spreader stokers occurs while it is still in suspension. The type of coal being fired has a uniform effect on PM emissions for all types of coal-fired boilers. Firing coals with higher ash content results in higher PM emissions. Ash fusion temperature also has an indirect effect on PM emissions. Coals with high ash fusion temperatures are generally fired in dry-bottom units and emit higher levels of PM.

PM emissions from coal-fired industrial boilers also depend on the boiler load. Limited test data indicate that mass emissions of PM on a heat input basis tend to decrease with decreasing load.[55] The data are scattered and the rate of change of PM emissions varies from one boiler to another so that a general correlation is not possible. However, for each boiler firing type the general trend of decreasing PM emissions with decreasing load exists.

The variation of particle size as a function of boiler type is shown in Table 3-13. As can be seen, spreader and chaingrate stokers emit coarser particles (mass median diameters of 59 to 88 μm) than do underfeed stokers and pulverized coal-fired units (mass median diameter of about 17 μm).

Sulfur oxide emissions, as mentioned earlier, are directly proportional to the sulfur content of the fuel. Emission factors from AP-42[26] which are used in this study neglect differences in emissions due to differences in ash partitioning and sodium content in the fuel. As noted earlier, they assume that about 95 percent of the fuel sulfur is emitted as gaseous SO_2 and SO_3, with the remaining 5 percent adsorbed on the fly ash or bottom ash. Individual fuel characteristics will result in deviations from these values.

According to Table 3-11, nitrogen oxides emission rates are lowest for chaingrate and underfeed stokers, at 140 and 150 ng/J (0.33 and 0.35 lb/10^6 Btu), respectively. Both spreader stokers and pulverized units emit almost twice as much NO_x as chaingrate stokers. Underfeed and chaingrate stokers have very large fireboxes and consequently lower

TABLE 3-13. PARTICLE SIZE DATA FOR PARTICULATE EMISSIONS FROM TYPICAL UNCONTROLLED COAL-FIRED INDUSTRIAL BOILERS [56,57,58]

Firing method	Particle mass median diameter, μm
Pulverized	17
Spreader stoker	59
Chaingrate stoker	88
Underfeed stoker	16

volumetric and surface heat release rates. The lower heat release rates reduce peak temperatures and, hence, contribute to lower NO_x emissions.[59] In addition, the partial staged combustion that naturally occurs in all stokers due to combustion on fuel beds contributes to reduced NO_x emissions relative to pulverized coal-fired units.[60]

Figure 3-7 shows how excess oxygen levels affect NO_x emissions for the various coal-fired boiler types discussed. More information on this subject is presented in Section 4.3.7 of this report. For the typical pulverized coal-fired unit discussed earlier, the 30 percent excess air being fired translates to approximately 5 percent excess oxygen on the figure. Similarly, for the three types of stokers, all with 50 percent excess air, this translates to approximately 7 percent excess oxygen. Thus, as can be seen in Figure 3-7, an increase in excess oxygen from 5 to 6 percent for pulverized coal-fired units leads to roughly a 20 ng/J increase in NO_x emissions, while an increase in excess oxygen from 7 to 8 percent for the stokers leads to roughly a 25 ng/J increase in NO_x emissions.

Reducing boiler load tends to decrease combustion intensity which in turn tends to decrease NO_x emissions. However, load reduction is typically accompanied by an increase in excess oxygen which may offset the decrease in NO_x emissions.

Carbon monoxide and hydrocarbon emissions are dependent on combustion efficiency. Generally their emission rate, defined as mass emissions per unit of energy input in ng/J, decreases with increasing boiler size. For example, HC emission rates are lowest for the pulverized coal units at 5 ng/J (0.01 lb/10^6 Btu); they are over three times higher for spreader stokers, and 10 times higher for underfeed and overfeed stokers as a result of increasingly less efficient combustion.

3.2.3 Oil-Fired Boilers

The different types of oil-fired boilers are discussed in this section and uncontrolled emission factors for each boiler type are discussed. Mass and energy balances are presented for representative boilers. The mass and energy balances were developed for the oil-fired boilers in the same manner as described in Section 3.2.2 for the coal-fired boilers. Representative

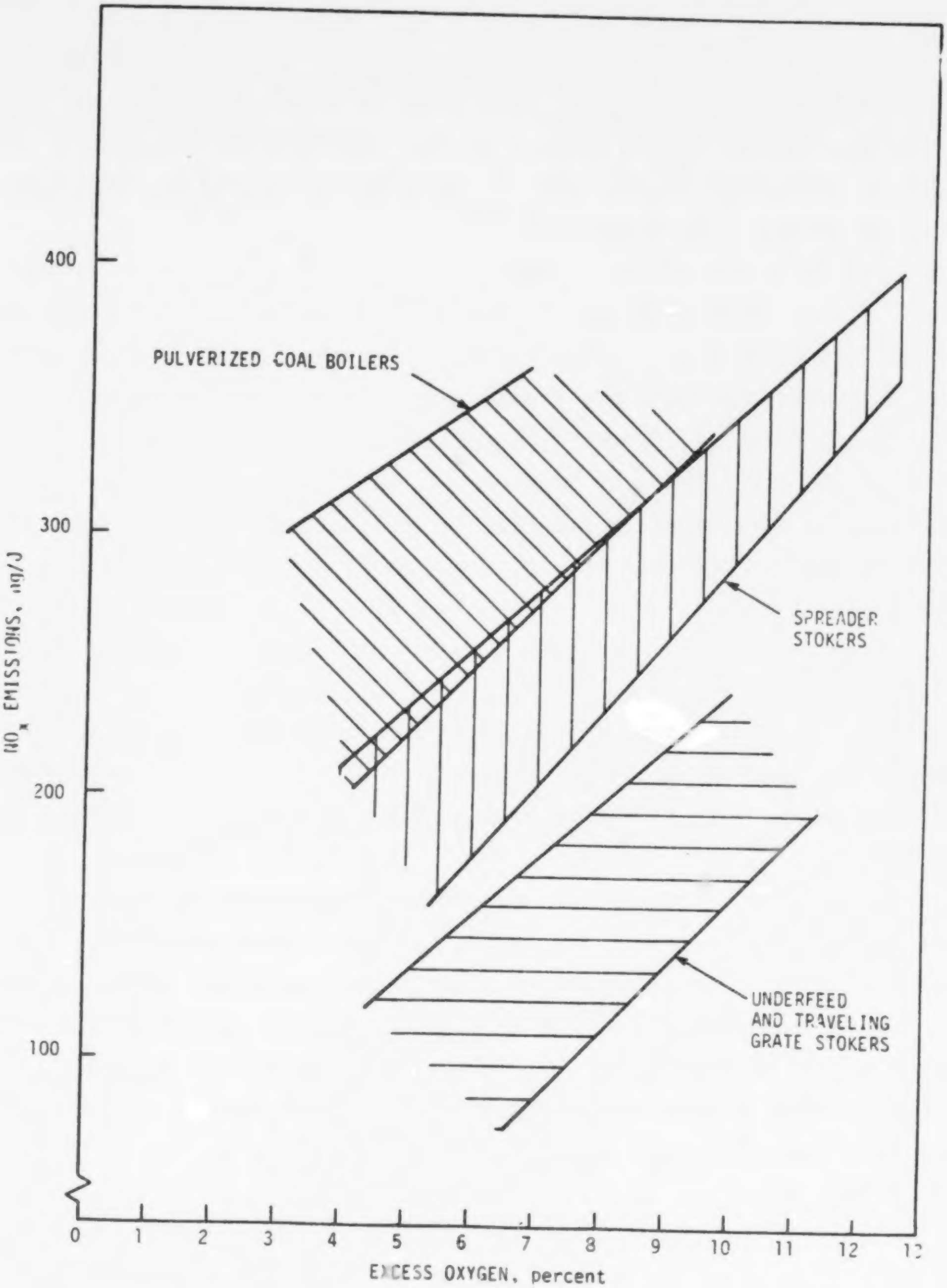


Figure 3-7. Effect of excess oxygen on NO$_x$ emission from coal-fired boilers.[61]

residual and distillate oil fuels were chosen to perform the mass balance. The ultimate analyses of these fuels are summarized in Table 3-14.

Oil storage and preparation is necessary at the boiler site to ensure that an adequate supply of fuel is on hand and ready for combustion. For distillate oil this may not require more than providing storage, but for residual oil the fuel is usually heated to keep the viscosity low enough for pumping and proper atomization. Oil-fired units are usually ignited with the primary fuel being fired, but may use natural gas for ignition.

Oil-fired industrial boilers can be classified into two main categories; watertube and firetube. Each of these boiler types is discussed in the following subsections. Following these subsections a separate subsection on emission factors is presented.

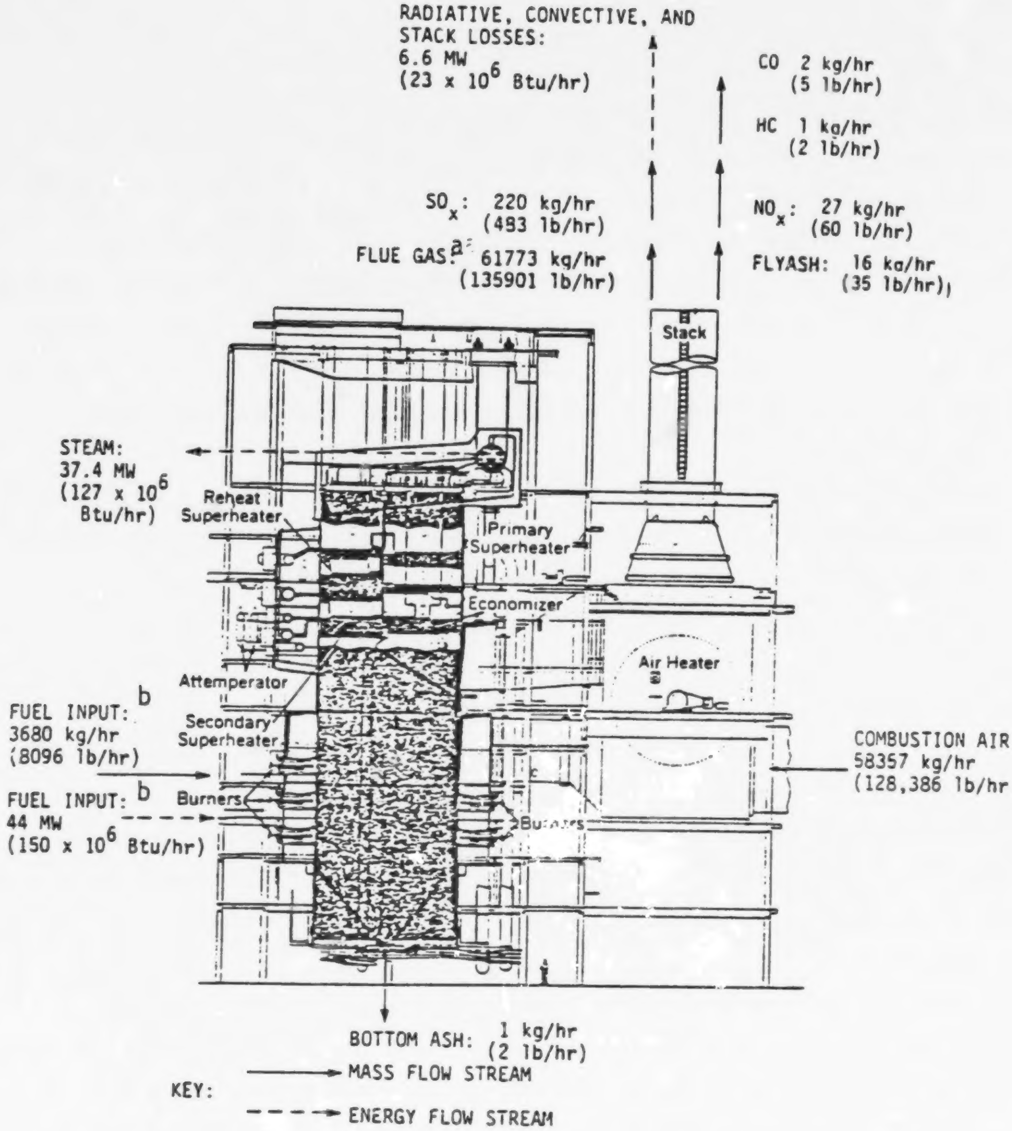
3.2.3.1 Watertube Boilers. Since the general characteristics of watertube boilers are discussed in Section 3.2.2.1, only the specifics of oil-fired units are discussed in this subsection. Oil-fired watertube boilers are generally less than 73.3 MW (250 x 10^6 Btu/hr) heat input. These boilers are subclassified according to the configuration of the heat transfer tubes. Straight watertube boilers are no longer manufactured, having been completely supplemented by firetube boilers in the smaller sizes and bent watertube boilers in the larger sizes. However, a large number of straight tube boilers are still in operation. Both types of boilers may fire either residual or distillate oil and may be further classified according to how the fuel is atomized (steam, air, or mechanical).

Figure 3-8 illustrates a typical bent tube, oil-fired watertube boiler and gives the corresponding mass and energy balance. Mass and energy balances are shown for a 44 MW (150 x 10^6 Btu/hr) heat input residual oil-fired unit, operating at 85 percent efficiency and 15 percent excess air. Such a unit would typically include an economizer, which preheats the feedwater, and an air preheater, which heats the combustion air.

3.2.3.2 Firetube Boilers. Oil-fired firetube boilers are subclassified in the same manner as coal-fired firetube boilers. These six subclassifications are horizontal return tubular (HRT), Scotch marine,

TABLE 3-14. ULTIMATE ANALYSES OF RESIDUAL AND DISTILLATE OIL SELECTED FOR REPRESENTATIVE BOILERS[38]

Fuel	Composition percent by weight							Heating value, kJ/kg (Btu/lb)
	Water	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Residual oil	0.08	86.62	10.20	0.3	Trace	3.00	0.10	43,043 (18,500)
Distillate oil	0.05	87.17	12.28	0.05	Trace	0.50	Trace	45,346 (19,500)


RADIATIVE, CONVECTIVE, AND STACK LOSSES:
6.6 MW
(23 x 10^6 Btu/hr)
CO 2 kg/hr
(5 lb/hr)
HC 1 kg/hr
(2 lb/hr)
SOx: 220 kg/hr
(483 lb/hr)
NOx: 27 kg/hr
(60 lb/hr)
FLUE GAS:a 61773 kg/hr
(135901 lb/hr)
FLYASH: 16 kg/hr
(35 lb/hr)
Stack
STEAM:
37.4 MW
(127 x 10^6 Btu/hr)
Reheat Superheater
Primary Superheater
Economizer
Air Heater
Attemperator
FUEL INPUT:b
3680 kg/hr
(8096 lb/hr)
Secondary Superheater
COMBUSTION AIR
58357 kg/hr
(128,386 lb/hr
FUEL INPUT:b
44 MW
(150 x 10^6 Btu/hr)
Burners
Burners
BOTTOM ASH: 1 kg/hr
(2 lb/hr)
KEY:
MASS FLOW STREAM
ENERGY FLOW STREAM

[a] Flue gas is defined in this figure as major components (O_2, N_2, CO_2, H_2O).
[b] Fuel is 3 percent sulfur residual fuel (Table 3-14).

Figure 3-8. Mass and energy balances for a 44 MW (150 x 10^6 Btu/hr) residual oil-fired watertube boiler.

vertical, locomotive, short firebox, and compact boilers. The HRT, Scotch marine, and vertical units are discussed below.

Horizontal Return Tubular

In a HRT boiler the firetubes are horizontal. The fuel firing mechanism is at one end, and the products of combustion are recirculated or "returned" to make two, three, or four passes through the tubes within a water medium. The boiler is encased with brick, and the furnace is set on rollers or suspended on hangers to allow for expansion and contraction.

Scotch Marine

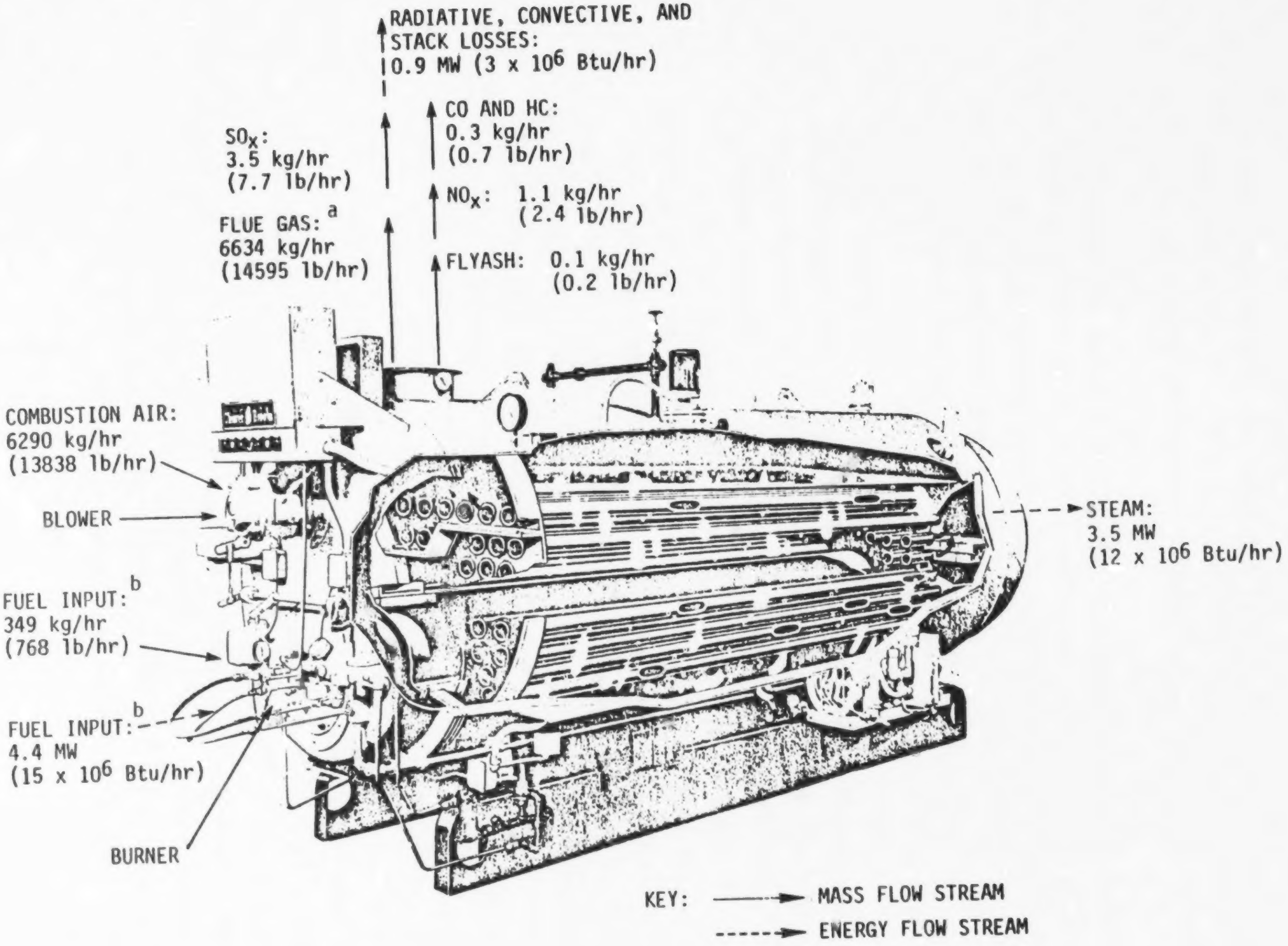
Scotch marine boilers consist of a water-cooled furnace and firetubes. The boiler and the furnace are housed in one continuous containment shell; fuel is burned in the lower half of the unit. The combustion gases first pass through the furnace tube, heating the bottom of the water basin, and then pass through the firetubes, heating the water in the basin. Scotch marine boilers are available as two-, three-, or four-pass units.

Scotch marine boilers are complete, compact, portable, packaged units. Figure 3-9 shows a mass and energy balance for a typical distillate oil-fired Scotch marine firetube boiler. The calculations are based on a 4.4 MW (15 x 10^6 Btu/hr) heat input unit, operating at 15 percent excess air (equivalent to 3 percent excess oxygen) and 80 percent efficiency.[63]

Vertical

Vertical boilers are single-pass units with firetubes arranged vertically up from the water-cooled furnace and may be either exposed-tube or submerged-tube type. These complete furnace and boiler units are small and portable, requiring less space than comparable HRT or Scotch marine boilers.

Only the fuel feed mechanism and burners differ between the oil-fired and the coal-fired types for each of these boilers. Oil-fired burners for firetube boilers employ the same atomization techniques as for watertube units. Likewise, the same general effects on emission factors are noted for both boiler types. Firetube boilers may fire either residual or distillate fuel oils.


RADIATIVE, CONVECTIVE, AND STACK LOSSES: 0.9 MW (3 x 10⁶ Btu/hr)
CO AND HC: 0.3 kg/hr (0.7 lb/hr)
SO$_x$: 3.5 kg/hr (7.7 lb/hr)
NO$_x$: 1.1 kg/hr (2.4 lb/hr)
FLUE GAS:[a] 6634 kg/hr (14595 lb/hr)
FLYASH: 0.1 kg/hr (0.2 lb/hr)
COMBUSTION AIR: 6290 kg/hr (13838 lb/hr)
BLOWER
STEAM: 3.5 MW (12 x 10⁶ Btu/hr)
FUEL INPUT:[b] 349 kg/hr (768 lb/hr)
FUEL INPUT:[b] 4.4 MW (15 x 10⁶ Btu/hr)
BURNER
KEY:
MASS FLOW STREAM
ENERGY FLOW STREAM

---

[a] Flue gas in this figure means major components (O_2, N_2, CO_2, H_2O).

[b] Fuel is distillate oil.

Figure 3-9. Cutaway view of a four-pass Scotch firetube boiler.[64]

3.2.3.3 Emission factors for oil-fired boilers. The emission factors for oil-fired boilers are summarized in Table 3-15. These factors are typical of firetube as well as watertube oil-fired boilers in the given size ranges.

As noted earlier, particulate emissions from residual oil-fired boilers are expressed as a function of the sulfur content of the fuel. Assuming a fuel sulfur content of 3 percent (see Table 3-14), particulate emissions from residual oil-fired units are greater by roughly a factor of 15 than for distillate oil-fired boilers. This is due, in part, to the lower carbon residue content of distillate oil.

Figure 3-10 shows particulate emissions as a function of fuel oil carbon residue and illustrates the range of values that have been measured. As can be seen from Figure 3-10, industrial boilers firing oil containing little or no carbon residue emit from 5 to 20 ng/J of particulate matter.

The type of atomization has been shown to affect the amount of particulate matter emitted. One study on residual oil-fired units has shown that a mechanically atomized unit produces 20 times the particulate matter that a comparable air-atomized unit does (9.9 ng/J to 186.2 ng/J), and that steam atomization produces roughly three times as much particulate matter as air atomization (25.2 ng/J to 9.0 ng/J).[69] The same study indicates that mechanical atomization is the most common method of atomization, thus accounting for the fact that the emission factor in Table 3-15, which represents the current mix of installed atomization techniques, is 96.0 ng/J, a factor close to the high end of the range. This is based on a fuel sulfur content of 3 percent.

As noted in Table 3-15, NO_x emissions from oil-fired boilers are subject to a wide variety of influences which can interact to affect emission rates. In general, boilers firing residual oil emit more NO_x than equivalent boilers firing distillate oil. Furthermore, the range of NO_x emissions is wider for boilers firing residual oil. Both these trends are accounted for by the larger amount and higher variability of fuel nitrogen in residual oil.

TABLE 3-15. UNCONTROLLED EMISSIONS FACTORS FOR OIL-FIRED INDUSTRIAL BOILERS [d] [ng/J (lb/10^6 Btu)]

Pollutant	Fuel Type	
	Residual	Distillate
Particulate Matter (PM)[b]	29.1 S + 8.72 (0.0675 S + 0.0203)	6.30 (0.0146)
Sulfur Dioxide (SO_2)[b]	456 S (1.06 S)	447 S (1.04 S)
Nitrogen Oxides (NO_x)	a	a
Carbon Monoxide (CO)	14.5 (0.0338)	15.8 (0.0366)
Hydrocarbons (HC)	2.90 (0.00675)	3.15 (0.00732)
Lead (Pb)[c]	0.065 (0.00015)	No data

[a] NO_x emissions are strongly dependent on boiler type, fuel nitrogen level, amount of air preheat, and excess air. Reference 66 gives the following ranges:

Residual	- Firetube	111 to 170 ng/J (0.257 to 0.395 lb/10^6 Btu)
	Watertube (w/o air preheat)	87.5 to 362 ng/J (0.203 to 0.841 lb/10^6 Btu)
	Watertube (w/air preheat)	66.8 to 188 ng/J (0.155 to 0.437 lb/10^6 Btu)
Distillate	- Firetube (w/air preheat)	96.5 to 107 ng/J (0.224 to 0.249 lb/10^6 Btu)
	Watertube (w/o air preheat)	44.7 to 59.5 ng/J (0.104 to 0.138 lb/10^6 Btu)
	Watertube (w/air preheat)	69.0 to 102 ng/J (0.160 to 0.237 lb/10^6 Btu)

[b] S is the sulfur content of the fuel in weight percent. The emission factor for residual oil represents the current mix of installed atomization techniques.

[c] Based on one test only (Reference 67).

[d] Sources - Reference 68 for PM, SO_2, CO, & HC
Reference 66 for NO_x.
Reference 67 for Pb.

Reference 68 expresses emissions on a lb/1000 gal. fuel burned basis. Conversion factors of 43,043 kJ/kg (18,500 Btu/lb) and 45,345 kJ/kg (19,500 Btu/lb) were used to convert factors to a heat input basis for residual and distillate oil respectively. Densities of 0.96 kg/ℓ (8.0 lb/gal) and 0.84 kg/ℓ (7.0 lb/gal) were also used.

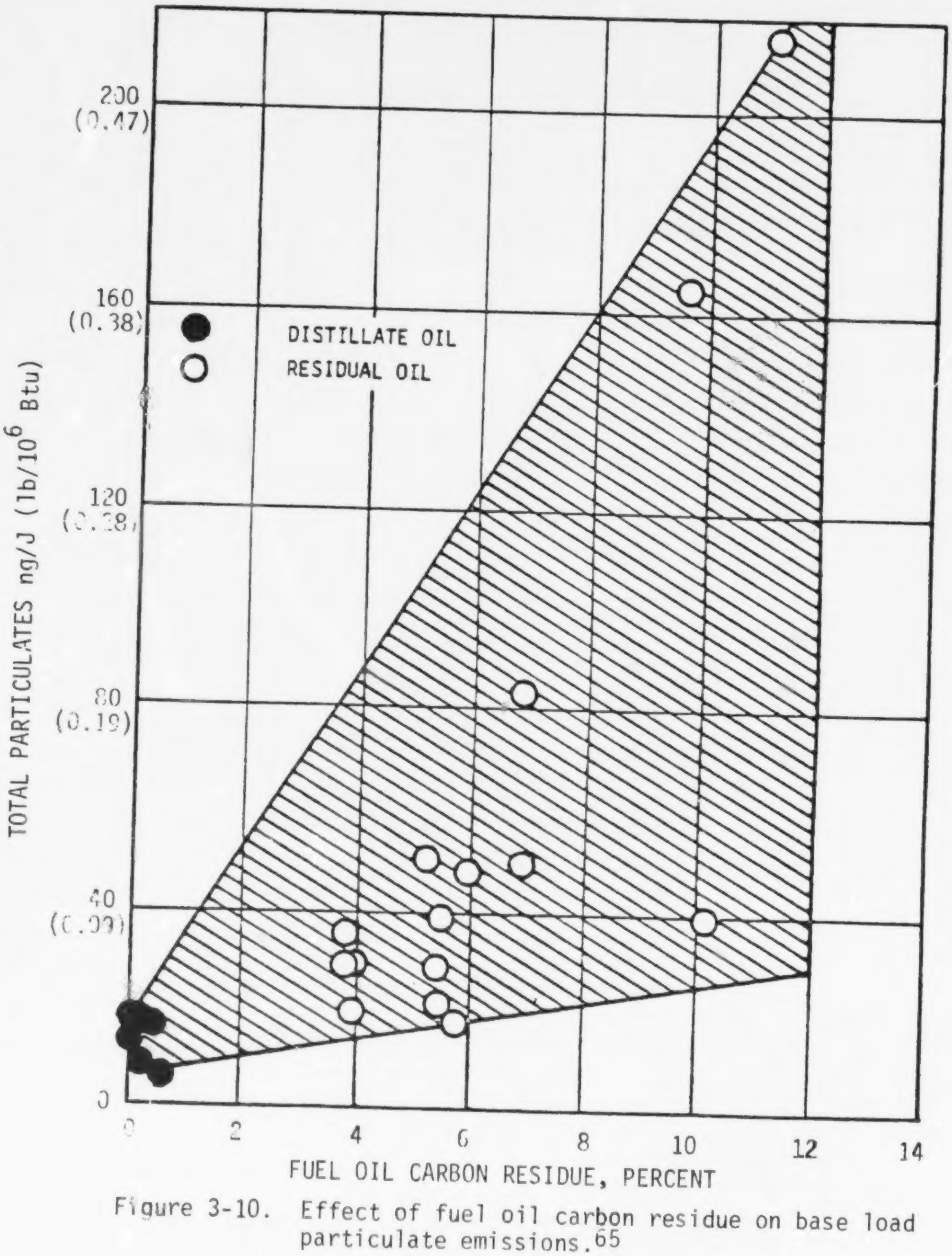


Figure 3-10. Effect of fuel oil carbon residue on base load particulate emissions.[65]

Air-to-fuel ratios (typically expressed in terms of excess oxygen) tend to affect NO_x emissions from residual oil-fired units more than distillate oil-fired units, as shown in Figure 3-11. In all cases, increased excess oxygen leads to higher NO_x emissions. However, the rate of increase with increased oxygen levels is larger for the heavier, residual oils. Section 4.3.7 discusses the variation in NO_x emissions with respect to excess air levels in more detail.

The effect of load variation on NO_x emissions is similar to the effect on coal-fired boilers. Available data indicate both increases and decreases in NO_x emissions at reduced loads depending on whether or not excess air is held constant during load reduction.[70]

3.2.4 Natural Gas-Fired Boilers

Natural gas-fired industrial boilers are classified in two main categories, watertube and firetube. A mass and energy balance, developed in the same manner as for the coal- and oil-fired boilers is given for a representative natural gas-fired industrial boiler. The ultimate analysis of natural gas selected to perform the mass balance is presented in Table 3-16. Uncontrolled emission factors for these boilers are presented at the conclusion of this section.

3.2.4.1 Watertube Boilers. Units firing natural gas alone are generally similar in design, but physically smaller, to those units firing only oil for the same output. These units are generally smaller than 73.3 MW (250×10^6 Btu/hr) heat input.[71]

3.2.4.2 Firetube Boilers. Natural gas-fired firetube boilers are similar to oil-fired firetube boilers except for the burner. As with watertube boilers, natural gas does not have to be atomized to be fired in the firetube units, and only occasionally is a spray gun mechanism designed for a natural gas burner. These units are generally designed for less than 7.3 MW (25×10^6 Btu/hr) heat input.[72]

Figure 3-9, introduced earlier, shows a firetube boiler that can be fired with oil or natural gas, and a mass and energy balance for oil firing. Table 3-17 presents a comparable mass and energy balance for the same unit firing gas. These calculations are based on a boiler with a heat input of

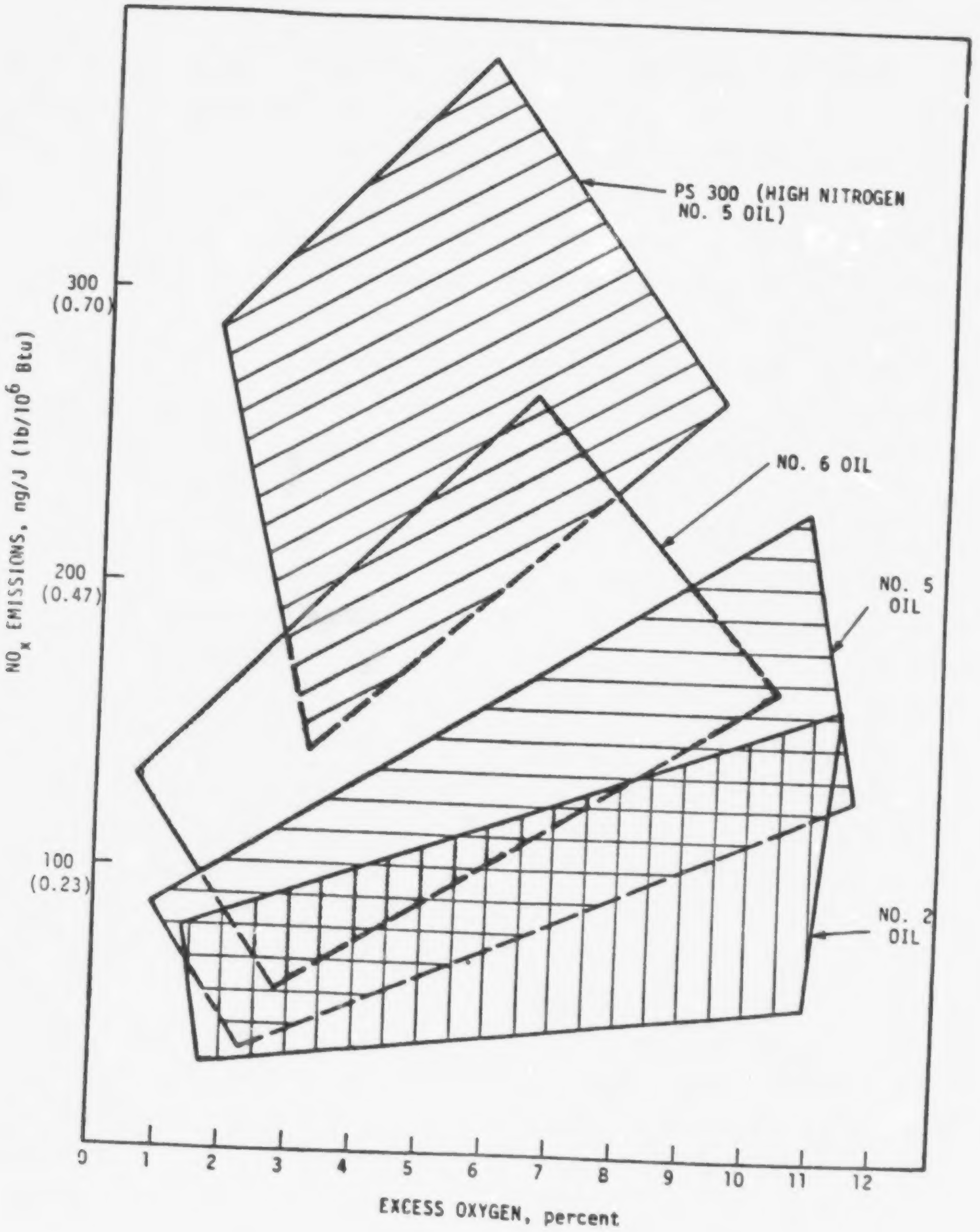


Figure 3-11. Effect of excess oxygen on NO_x emissions from distillate and residual oil-fired boilers.[61]

TABLE 3-16. ULTIMATE ANALYSIS OF NATURAL GAS SELECTED FOR THE REPRESENTATIVE BOILER[38]

Fuel	Composition percent by weight							Heating value, kJ/kg (Btu/lb)
	Water	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Natural l gas	0.02	69.26	22.67	8.05	Trace	Trace	0	50,707 (21,800)

TABLE 3-17. MASS AND ENERGY BALANCE FOR A NATURAL GAS-FIRED FIRETUBE BOILER[a]

ENERGY BALANCE		
In		
Fuel input:		4.4 MW (15 x 10^6 Btu/hr)
Out		
Steam output:		3.5 MW (12 x 10^6 Btu/hr)
Convective, radiative, and stack losses:		0.9 MW (3 x 10^6 Btu/hr)
MASS BALANCE		
In		
Fuel in:		312 kg/hr (688 lb/hr)
Combustion air:		5741 kg/hr (12660 lb/hr)
Out		
Stack Components:	Flyash:	0.07 kg/hr (0.15 lb/hr)
		0.005 kg/hr (0.01 lb/hr)
		0.80 kg/hr (1.8 lb/hr)
		0.12 kg/hr (0.28 lb/hr)
		0.02 kg/hr (0.05 lb/hr)
	Major Components:[b]	6054 kg/hr (13,350 lb/hr)

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[a] Refer to Figure 3-9 for locations of each mass and energy flow.

[b] Major components are CO_2, O_2, N_2, H_2O.

4.4 MW (15 x 10^6 Btu/hr), 15 percent excess air, and an 80 percent efficiency.[73]

3.2.4.3. Emission Factors for Natural Gas-Fired Boilers. Typical emission factors for natural gas-fired industrial boilers (watertube and firetube) are summarized on Table 3-18. As noted in the table, NO_x emissions show wide variability depending on a variety of factors. In the case of natural gas-fired boilers, the major factors are those associated with the formation of thermal NO_x, since fuel NO_x is usually negligible in natural gas (the nitrogen percentage shown in Table 3-16 is free nitrogen and does not contribute to fuel NO_x emissions). As explained earlier, peak flame temperatures and excess air are the major influences on thermal NO_x formation. Since air preheaters increase peak flame temperatures, use of this device may increase NO_x emissions up to twofold (see Table 3-18) for watertube boilers. Another influence on flame temperatures is boiler size. Larger boilers tend to operate at higher flame temperatures than smaller ones, increasing NO_x emissions.[76] The type of boiler (watertube or firetube) does not appear to have a large effect on NO_x emissions provided other factors are held constant. The limited data available indicate no difference between NO_x emissions of firetube boilers and those of small single burner watertube boilers without air preheat.[76]

Excess air variations affect NO_x emissions for natural gas-fired industrial boilers as shown in Figure 3-12. Typical natural gas-fired boilers operate at 15 percent excess air or 3 percent oxygen. The effect of excess air on watertube boilers with air preheaters is most significant, with roughly a 20 percent increase in NO_x emissions per 1 percent increase in excess oxygen. Load variations appear to affect NO_x emissions from gas-fired boilers more uniformly than they affect emissions from coal- or oil-fired boilers. Reduction in NO_x emissions occurs with load reduction for natural gas-fired boilers, with the most significant effect being on boilers with air preheat.

SO_x emissions from natural gas-fired boilers are very low due to the fact that natural gas generally contains less than 0.1 percent sulfur. Sulfur-containing mercaptan, however, is added to natural gas for detection

TABLE 3-18. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS-FIRED WATERTUBE AND FIRETUBE INDUSTRIAL BOILERS[a,c]

[ng/J (lb/10^6 Btu)]

Pollutant	Emission Factor
Particulate matter (PM)	2.05 - 6.58 (0.00508 - 0.0153)
Sulfur dioxide (SO_2)[c]	0.262 (0.000610)
Nitrogen oxides (NO_x)	b
Carbon monoxide (CO)	7.44 (0.0173)
Hydrocarbons (HC)	1.31 (0.00305)

[a] Reference 74 used for all factors except NO_x. Units converted using a heating value of 50707 kJ/kg (21,800 Btu/lb) and density of 0.722 kg/m^3 (0.0451 lb/ft^3).

[b] NO_x emissions strongly dependent on boiler type, air preheat and excess air levels. Reference 75 gives the following ranges:

Firetube	- 28.6 - 55.1 ng/J (0.066 - 0.128 lb/10^6 Btu)
Watertube w/o air preheater	- 30.1 - 97.9 ng/J (0.070 - 0.228 lb/10^6 Btu)
Watertube w/ air preheat	- 49.0 - 190.1 ng/J (0.114 - 0.444 lb/10^6 Btu)

[c] Assumes pipeline quality natural gas.

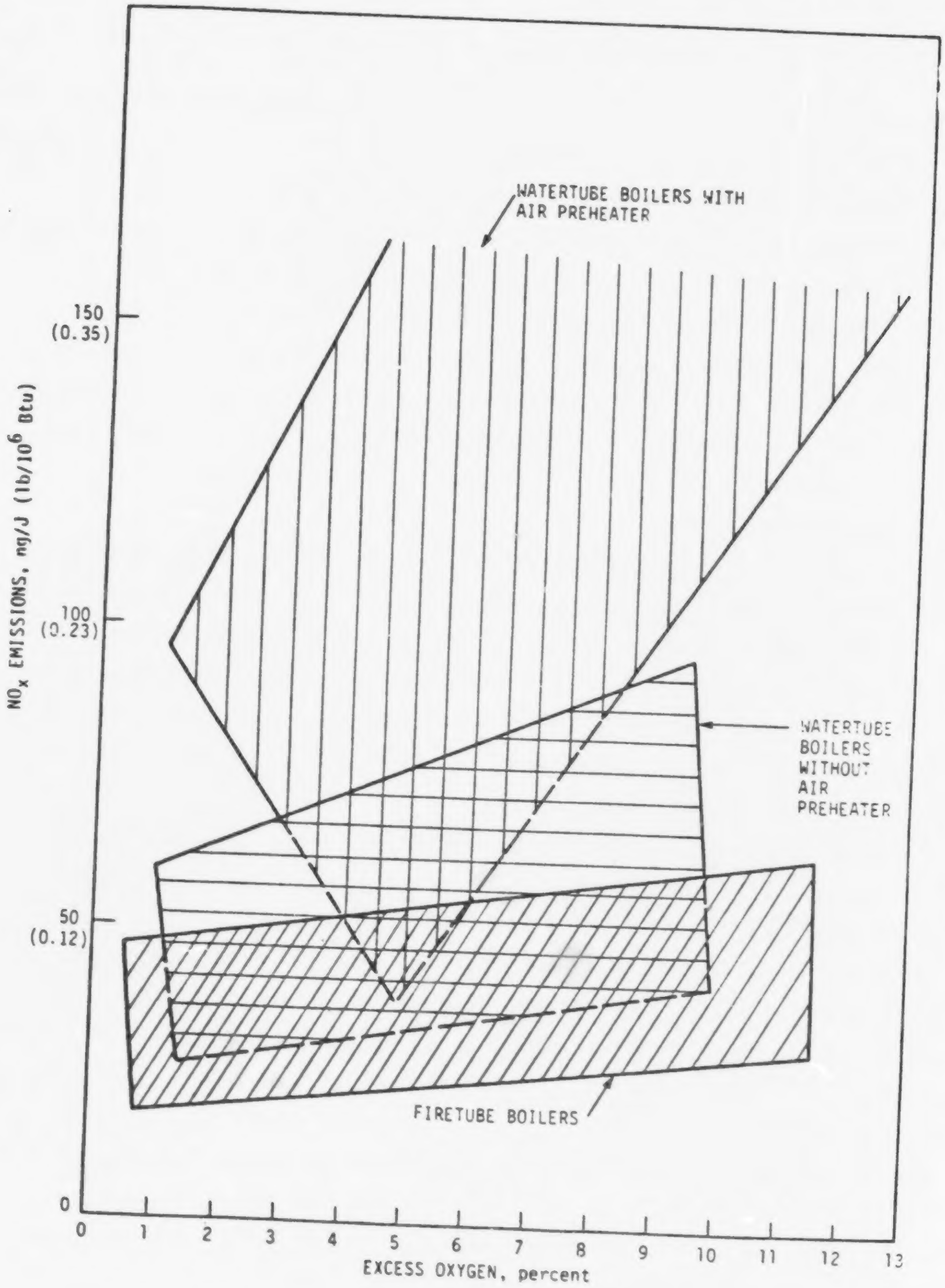

Figure 3-12. Effect of excess oxygen on NO_x emissions from natural gas-fired boilers.[61]

purposes, leading to small amounts of SO_x emissions along with the fuel sulfur available.

3.3 EMISSIONS UNDER CURRENT REGULATIONS

As previously discussed (Section 3.2), industrial boilers emit a number of pollutants, including sulfur oxides (SO_x), nitrogen oxides (NO_x), particulate matter (PM), and lesser amounts of carbon monoxide (CO), hydrocarbons, and trace elements. Of these pollutants, however, only NO_x, SO_x, and PM are directly subject to emission limitations under existing State or Federal regulations. This section discusses existing regulations (both State and Federal) to which industrial boilers are subject.

3.3.1 Existing Regulations

3.3.1.1 Subpart D Emission Limits. New fossil fuel-fired industrial boilers with capacities greater than 73.3 MW (250 x 10^6 Btu/hr) are subject to 40 CFR 60, Subpart D which limits NO_x, SO_x, and PM emissions. Most states have been delegated the authority to administer New Source Performance Standards (NSPS) and therefore have incorporated the provisions of Subpart D as part of their State implementation plan (SIP) for new units with capacities greater than 73.3 MW.

The currently applicable NSPS mass emission limits are presented in Table 3-19. Subpart D for fossil fuel-fired steam generators excludes facilities using lignite coals from the NO_x standard.

Subpart D also specifies an opacity limit for all boilers subject to its provisions. The opacity standard limits visible emissions to 20 percent opacity except for one six-minute average per hour which may be up to 27 percent.

3.3.2 State Emission Limits

New boilers with capacities less than 73 MW are subject to State emission limits for NO_x, SO_x and PM. Particulate emissions are typically limited by both an opacity or visible emission limit and a mass emission limit. There is limited State regulation of NO_x. Only Illinois has a limit for CO emissions (no greater than 200 ppm at 50 percent excess air).

TABLE 3-19. SUBPART D EMISSION LIMITS FOR FOSSIL FUEL-FIRED STEAM GENERATORS

[>73.3 MW (250 x 10^6 Btu/hr)]

Fuel	PM ng/J (lb/10^6 Btu)	SO_x ng/J (lb/10^6 Btu)	NO_x[a] ng/J (lb/10^6 Btu)
Coal	43 (0.10)	520 (1.2)	300 (0.70)
Fuel Oil	43 (0.10)	340 (0.80)	130 (0.30)
Natural gas	43 (0.10)		86 (0.20)

[a] Excluding lignite.

SIPs reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably from state to state. In addition, State emission limits usually reflect the fuel mix in a particular state. States that depend on natural gas or fuel oils for their energy needs typically have more stringent PM and SO_2 emission limits than coal burning states. Mid-western states, with large reserves of high-sulfur, high ash coal, tend to have relatively lenient PM and SO_2 emission limits.

The type of PM regulation used by the majority of states is a sliding scale emission limit across a capacity range, which becomes more stringent as the capacity of the units increases. In states with this type of PM emission limit, the variable emission limit usually begins above the 2.9 MW (10 x 10^6 Btu/hr) capacity. For units with capacities of less than 2.9 MW (10 x 10^6 Btu/hr), the PM emission limit is, in most cases, 258 ng/J (0.60 lb/10^6 Btu). The emission limit then becomes progressively more stringent to 73.3 MW (250 x 10^6 Btu/hr) capacity, at which point the Subpart D requirements generally are more stringent than the SIP limits for new boilers. Therefore, for units with capacities above 73.3 MW (250 x 10^6 Btu/hr), the PM emission limit is 43 ng/J (0.1 lb/10^6 Btu). A summary of the SIP particulate emission limits is presented in Table 3-20.

Unlike SIP PM emission limits, SO_2 limits do vary with the type of fuel fired. There is usually a limit for coal-fired boilers and a separate limit for oil- or gas-fired boilers. Within each fuel category, there is usually a single SO_2 emission limit that applies across the capacity range and is based on either SO_2 mass emission limits or fuel sulfur content. Tables 3-21 and 3-22 list the allowable SIP SO_2 emissions for new and existing coal-fired boilers and for oil and natural gas-fired boilers, respectively.

NO_x emissions from new boilers with capacities above 73.3 MW (250 x 10^6 Btu/hr), as already mentioned, are subject to Subpart D. EPA has delegated authority for implementation of this standard to most states, and it is now part of each SIP. Few states have any limitation on NO_x emissions from new boilers smaller than those subject to Subpart D. Table 3-23 summarizes the data for states with NO_x emission limits different from Subpart D.

Table 3-20. STATE PARTICULATE REGULATIONS (lb/10^6 Btu)[77]

State	Existing	New
Alabama	$E = 3.109H^{-0.589}$ (class 1), $E = 3.109H^{-0.589}$ (class 2)	$E = 1.38H^{-0.44}$ (class 1), $E = 3.109H^{-0.589}$ (class 2)
Alaska	0.1 gr/scf	0.1 gr/scf
Arizona	$E = 1.02H^{-0.769}$	$E = 1.02H^{-0.769}$
Arkansas	Ambient concentrations may not exceed 75 μg/m³ above background	Ambient concentrations may not exceed 75 μg/m³ above background
California	10 lb/hr or 0.1 gr/scf generally; however, each county has separate regulations	10 lb/hr or 0.1 gr/scf generally; however, each county has separate regulations
Colorado	$E = 0.5H^{-0.26}$	$E = 0.5H^{-0.26}$
Connecticut	0.2	0.1
Delaware	0.3	0.3
District of Columbia	$E = 0.17455H^{-0.23522}$	$E = 0.17455H^{-0.23522}$
Florida	Best available technology or 0.1 lb/10^6 Btu	Best available technology or 0.1 lb/10^6 Btu
Georgia	$E = 1.11H^{-0.202}$	$E = 1.584H^{-0.5}$
Hawaii	None for coal and oil	None for coal and oil
Idaho	$\log E = -0.23 \log H - 2.0111$	$\log E = -0.23 \log H - 2.0111$
Illinois	$E = 5.18H^{-0.715}$	$E = 5.18H^{-0.715}$
Indiana	$E = 0.87H^{-0.16}$	$E = 0.87H^{-0.16}$
Iowa	0.8 maximum	0.6 maximum
Kansas	$E = 1.026H^{-0.233}$	$E = 1.026H^{-0.233}$

(continued)

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr)

Table 3-20. (continued)

State	Existing		New	
Louisiana	0.6		0.6	
Maine	$E = 1.08H^{-0.256}$		$E = 1.08H^{-0.256}$	
Maryland	Residual oil H<10	0.03 gr/scfd	Residual oil H<10	0.03 gr/scfd
	Residual oil 10<H<50	0.025 gr/scfd	Residual oil 10<H<50	0.025 gr/scfd
	Residual oil 50<H<200	0.02 gr/scfd	Residual oil 50<H<200	0.02 gr/scfd
	Residual oil 200>H	0.02 gr/scfd	Residual oil 200>H	0.01 gr/scfd
	Solid fuel H<200	0.05 gr/scfd	Solid fuel H<200	0.05 gr/scfd
	Solid fuel H>200	0.03 gr/scfd	Solid fuel H>200	0.03 gr/scfd
Massachusetts	0.15		0.1	
Michigan	Pulverized coal <100,000 lb steam/hr, 3 lb/1,000 lb flue gas; >100,000 lb steam/hr: $y = 6.75H^{-0.176}$ y = lb/1,000 lb flue gas		Pulverized coal <100,000 lb steam/hr, 3 lb/1,000 lb flue gas; >100,000 lb steam/hr: $y = 6.75H^{-0.176}$ y = lb/1,000 lb flue gas	
	Stoker coal 0-100,000 lb steam/hr, 0.65 lb/1,000 lb flue gas; 100,000-300,000 lb steam/hr, 0.65-0.45 lb/1,000 lb flue gas		Stoker coal 0-100,000 lb steam/hr, 0.65 lb/1,000 lb flue gas; 100,000-300,000 lb steam/hr, 0.65-0.45 lb/1,000 lb flue gas	
Minnesota	0.4		0.4	
Mississippi	$E = 0.896H^{-0.174}$		$E = 0.896H^{-0.174}$	
Missouri	$\log E = -0.23299 \log H + 2.1454$		$\log E = -0.3382 \log H + 2.1454$	
Montana	$E = 0.865H^{-0.159}$		$E = 1.026H^{-0.233}$	
Nebraska	$E = 1.026H^{-0.233}$		$E = 1.026H^{-0.233}$	
Nevada	$E = 1.02H^{-0.2131}$		$E = 1.02H^{-0.2131}$	

(continued)

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr)

Table 3-20. (continued)

State	Existing	New
New Hampshire	$E = 0.865H^{-0.159}$	$E = 0.985H^{-0.215}$
New Jersey	$E = 2.38H^{-0.598}$	$E = 2.38H^{-0.598}$
New Mexico	$E = 0.96135H^{-0.23471}$	$E = 0.96135H^{-0.23471}$
New York	$E = 1.02H^{-0.29}$	$E = 1.02H^{-0.219}$
North Carolina	$E = 1.09H^{-0.2594}$	$E = 1.09H^{-0.2594}$
North Dakota	$E = 0.811H^{-0.131}$	$E = 0.811H^{-0.131}$
Ohio	[a]	[a]
Oklahoma	$E = 1.09H^{-0.259}$	$E = 1.09H^{-0.259}$
Oregon	0.2 gr/scf	0.1 gr/scf
Pennsylvania	0.4 for <50 x 10^6 Btu/hr and $E = 3.6H^{-0.56}$ for >50 x 10^6 Btu/hr	0.4 for <50 x 10^6 Btu/hr and $E = 3.6H^{-0.56}$ for >50 x 10^6 Btu/hr
Rhode Island	0.2	0.2
South Carolina	0.6	0.6
Tennessee	$E = 1.09H^{-0.2549}$	$E = 2.16H^{-0.5566}$
Texas	0.3	0.3
Utah	$E = 1.58H^{-0.5}$	$E = 1.58H^{-0.5}$
Vermont	$E = 1.58H^{-0.5}$	$E = 1.58H^{-0.5}$
Virginia	$E = 0.8425H^{-0.2314}$	$E = 0.8425H^{-0.2314}$
Washington	0.2 gr/scf	0.1 gr/scf
West Virginia	$E = 0.706H^{-0.317}$	$E = 0.706H^{-0.314}$
Wisconsin	$E = 0.87H^{-0.16}$	$E = 0.87H^{-0.16}$
Wyoming	$E = 0.896H^{-0.174}$	$E = 0.896H^{-0.174}$

[a] For coal and residual oil, the emission limit varies between 0.1 and 0.4 lb/10^6 Btu depending on capacity and boiler location. For distillate oil and natural gas, the limit is 0.02 lb/10^6 Btu.

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr).

Table 3-21. STATE SO_2 REGULATIONS FOR COAL-FIRED BOILERS ($lb/10^6$ Btu)[77]

State	Existing	New
Alabama	4.0	1.8
Alaska	500 ppm	500 ppm
Arizona	1.0	0.8
Arkansas	<0.2 ppm ambient (assuming no control)	<0.2 ppm ambient (assuming no control)
California	200 lb/hr, 0.2% by volume, 1,000 ppm, or 0.5% S	200 lb/hr, 0.2% by volume, 1,000 ppm, or 0.5% S
Colorado	<500 ppm	<500 ppm
Connecticut	0.55	0.55
Delaware	1% S	1% S
District of Columbia	0.5% S	0.5% S
Florida	Latest available control technology or 6.17 for solid fuel	Latest available control technology or 6.17 for solid fuel
Georgia	2.5% S $<200 \times 10^6$ Btu/hr and 3% for $>200 \times 10^6$ Btu/hr	1.2% S
Hawaii	<2% S	<2% S
Idaho	<1.0% S	<1.0% S
Illinois	6.0	1.8
Indiana	6.0 for $H<23$, $E = 17.0H^{-0.33}$ for $23<H<3{,}000$, and 1.2 for $H>3{,}000$	6.0 for $H<23$, $E = 17.0H^{-0.33}$ for $12<H<3{,}000$, and 1.2 for $H>3{,}000$
Iowa	6.0	5.0
Kansas	No regulation below 250×10^6 Btu/hr	No regulation below 250×10^6 Btu/hr

E - emission limit ($lb/10^6$ Btu); H = heat input (10^6 Btu/hr)
% denotes maximum level sulfur that can be burned

Table 3-21. (continued)

State	Existing	New
Kentucky	$E = 9.464H^{-0.3740}$	$E = 9.46H^{-0.3740}$
Louisiana	Meet ambient regulations (assuming no control)	Meet ambient regulations (assuming no control)
Maine	<2.5% S	<2.5% S
Maryland	Low sulfur	Low sulfur
Massachusetts	0.55	0.28
Michigan	0.2	2.4
Minnesota	2% S	1.5% S
Mississippi	2.4	2.4
Missouri	2,000 ppm	500 ppm
Montana	<1	<1
Nebraska	2.5% S	2.5% S
Nevada	0.7	0.7
New Hampshire	1.5	1.5
New Jersey	2.0	1.5
New Mexico	No regulations	No regulations
New York	2.8	2.8
North Carolina	2.3	1.6
North Dakota	3.0	3.0
Ohio	5.70	5.70
Oklahoma	Meet ambient regulations	1.2
Oregon	1% S <150 x 10^6 Btu/hr, 1.6 >150 x 10^6 Btu/hr	1% S <150 x 10^6 Btu/hr, 1.6 >150 x 10^6 Btu/hr

(continued)

E = emission limit (lb/10^6); H = heat input (10^6 Btu/hr)
%S denotes maximum fuel sulfur that can be burned.

Table 3-21. (continued)

State	Existing	New
Pennsylvania	3.0 for <50 x 10^6 Btu/hr and $E = 5.1H^{-0.14}$ for >50 x 10^6 Btu/hr	1.0 for <50 x 10^6 Btu/hr and $E = 17H^{-0.14}$ for >50 x 10^6 Btu/hr
Rhode Island	≤0.55	≤0.55
South Carolina	3.5	2.3
South Dakota	3.0	3.0
Tennessee	4.0	1.6
Texas	3.0	3.0
Utah	1% S	1% S
Vermont	2% S	2% S
Virginia	2.64	1.06
Washington	2,000 ppm	1,000 ppm
West Virginia	3.2	1.6
Wisconsin	1.5% S	1.5% S
Wyoming	No regulations for <250 x 10^6 Btu/hr	No regulations for <250 x 10^6 Btu/hr

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr)
%S denotes maximum fuel sulfur that can be burned.

Table 3-22. STATE SO_2 REGULATIONS FOR OIL- AND GAS-FIRED BOILERS ($lb/10^6$ Btu)[77]

State	Existing	New
Alabama	4.0	1.8
Alaska	500 ppm	500 ppm
Arizona	2.2	0.8
Arkansas	<0.2 ppm ambient (assuming no control)	<0.2 ppm ambient (assuming no control)
California	200 lb/hr, 0.2% by volume, 1,000 ppm, or 0.5% S	200 lb/hr, 0.2% by volume, 1,000 ppm, or 0.5% S
Colorado	500 ppm	500 ppm
Connecticut	0.55	0.55
Delaware	1.0% S	0.3% S
District of Columbia	0.5% S	0.5% S
Florida	Latest technology or 2.75	Latest technology or 2.75
Georgia	2.5% for $<100 \times 10^6$ Btu/hr and 3.0% for $>100 \times 10^6$ Btu/hr	2.5% for $<100 \times 10^6$ Btu/hr and 3.0% for $>100 \times 10^6$ Btu/hr
Hawaii	No regulations	No regulations
Idaho	1.75% S for residual oil and 0.5% S for distillate oil	1.75% S for residual oil and 0.5% S for distillate oil
Illinois	1.0 for residual oil and 0.3 for distillate oil	1.0 for residual oil and 0.3 for distillate oil
Indiana	6.0 for $<23 \times 10^6$ Btu/hr, $E = 17.0H^{-0.33}$ for $23<H<3,000 \times 10^6$ Btu/hr, and 1.2 for $H>3,000 \times 10^6$ Btu/hr	6.0 for $<23 \times 10^6$ Btu/hr, $E = 17.0H^{-0.33}$ for $23<H<3,000 \times 10^6$ Btu/hr, and 1.2 for $H>3,000 \times 10^6$ Btu/hr

(continued)

E = emission limit ($lb/10^6$ Btu); H = heat input (10^6 Btu/hr)
%S denotes maximum fuel sulfur that can be burned.

Table 3-22. (continued)

State	Existing	New
Iowa	2.5	2.5
Kansas	No regulations	No regulations
Kentucky	$E = 5.6484H^{-0.354}$	$E = 5.6484H^{-0.354}$
Louisiana	2,000 ppm	2,000 ppm
Maine	<2.5% S	<2.5% S
Maryland	Low sulfur	Low sulfur
Massachusetts	0.55	0.28
Michigan	2.2	1.7
Minnesota	1.75	1.75
Mississippi	2.4	2.4
Missouri	2,000 ppm	500 ppm
Montana	1.0 for oil and 5 gr/100 ft^3 for gas	1.0 for oil and 5 gr/100 ft^3 for gas
Nebraska	2.5	2.5
Nevada	0.7	0.7
New Hampshire	1.5	1.5
New Jersey	2.0	1.5
New Mexico	0.34	0.34
New York	2.8	2.8
North Carolina	2.3	1.6
North Dakota	3.0	3.0
Ohio	3.2	1.0

(continued)

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr)
% S denotes maximum fuel sulfur that can be burned.

Table 3-22. (continued)

State	Existing	New
Oklahoma	0.8 for oil and 0.2 for gas	0.8 for oil and 0.2 for gas
Oregon	1.75% S for residual oil and 0.5% S for distillate oil	1.75% S for residual oil and 0.5% S for distillate oil
Pennsylvania	3.0 for <50 x 10^6 Btu/hr and $E = 5.1H^{-0.14}$ for >50 x 10^6 Btu/hr	1.0 for <50 x 10^6 Btu/hr and $E = 1.7H^{-0.14}$ for >50 x 10^6 Btu/hr
Rhode Island	≤0.55	≤0.55
South Carolina	3.5	2.3
South Dakota	3.0	3.0
Tennessee	4.0	1.6
Texas	440 ppm	440 ppm
Utah	1.5% S	1.5% S
Vermont	2% S	2% S
Virginia	2.64	1.06
Washington	2,000 ppm	1,000 ppm
West Virginia	3.1	1.6
Wisconsin	1.0% S for residual oil and 0.7% S for distillate oil	1.0% S for residual oil and 0.7% S for distillate oil
Wyoming	No regulations for <250 x 10^6 Btu/hr	No regulations for <250 x 10^6 Btu/hr

E = emission limit (lb/10^6 Btu); H = heat input (10^6 Btu/hr)
%S denotes maximum fuel sulfur that can be burned.

TABLE 3-23. STATE NO_x EMISSION LIMITS THAT DIFFER FROM SUBPART D[77]

State	NO_x emission limit, ng/J (lb/10^6 Btu) Coal	 Oil	 Gas	Capacity (10^6 Btu/hr)
Florida	300 (0.7)	130 (0.3)	86 (0.2)	>50
Oklahoma	300 (0.7)	130 (0.3)	86 (0.2)	>50
Wyoming	300 (0.7)	130 (0.3)	86 (0.2)	All
New Mexico	194 (0.45)	130 (0.3)	86 (0.2)	>50
California[a]	225 ppm	225 ppm	125 ppm	All

[a] California regulations vary with each control region; values given (at 3 percent O_2) are typical of emission limits for facilities other than those covered by Subpart D.

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4.0 EMISSION CONTROL TECHNIQUES

Uncontrolled emissions from industrial boilers were identified in Chapter 3. Emission control techniques potentially applicable to industrial boiler sources are described in this chapter. These descriptions include discussions of the design of each control technique, its status of development, and its applicability to industrial boilers. Also discussed are factors which affect the performance of the control techniques, including design parameters, operating conditions, and fuel quality. Emission data taken by approved EPA test methods to verify control technique performance is presented and discussed when available. Additional information on these tests is presented in Appendix C.

Portions of the control technology discussions contained in this chapter were excerpted from a series of Individual Technology Assessment Reports (ITAR's) prepared to assess the application of specific control techniques to industrial boilers. The ITAR's describe each technology in more detail than that presented in this chapter. Emissions test and system performance data reported in this chapter include both data reported in the ITAR's and data gathered subsequent to their preparation. Sources for these data are specifically referenced in Appendix C. The reader desiring additional information on any of the technologies discussed in this chapter is referred to the series of ITAR's listed in Table 4-1 and the other references listed at the end of this chapter and in Appendix C.

Control techniques discussed in this chapter are those meeting one of the following criteria:

- Currently used on industrial boilers or large pilot-scale installations;
- Currently applied in the utility or foreign sectors; technology transferability is indicated;
- Rapidly developing and likely to be commercially available in the next several years.

TABLE 4-1. ITAR REPORT LIST

Report	Report No.
Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning	EPA-600/7-79-178b
Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal	EPA-600/7-79-178c
Technology Assessment Report for Industrial Boiler Applications: Synthetic Fuels	EPA-600/7-79-178d
Technology Assessment Report for Industrial Boiler Applications: Fluidized-Bed Combustion	EPA-600/7-79-178e
Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification	EPA-600/7-79-178f
Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment	EPA-600/7-79-178g
Technology Assessment Report for Industrial Boiler Applications: Particulate Collection	EPA-600/7-79-178h
Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization	EPA-600/7-79-178i

This chapter is organized into six sections. The first three sections discuss post-combustion controls for particulate and sulfur dioxide (SO_2), and combustion modification for nitrogen oxides (NO_x) control, respectively. Section 4.4 discusses post-combustion controls for NO_x. Pre- combustion control techniques for particulate, NO_x, and SO_2 are discussed in Section 4.5, while fluidized bed combustion and other techniques involving combustion of a coal/alkali fuel mixture to control SO_2 emissions are presented in Section 4.6.

4.1 POST-COMBUSTION CONTROL TECHNIQUES FOR PARTICULATE MATTER

The post combustion control of particulate matter emissions from industrial boilers can be accomplished by using one or more of the following particulate control devices:

- electrostatic precipitators,
- fabric filters,
- wet scrubbers,
- side stream separators, or
- multitube cyclones (single and dual mechanical collectors)

These control devices are discussed separately in Sections 4.1.1 through 4.1.5. Test data documenting the performance of each of these control devices applied to industrial boilers are presented and discussed in Section 4.1.6.

4.1.1 Electrostatic Precipitators

The collection mechanism, factors affecting performance, status of development, and applicability of electrostatic precipitators (ESPs) to industrial boilers is discussed in this section.

4.1.1.1 Process Description

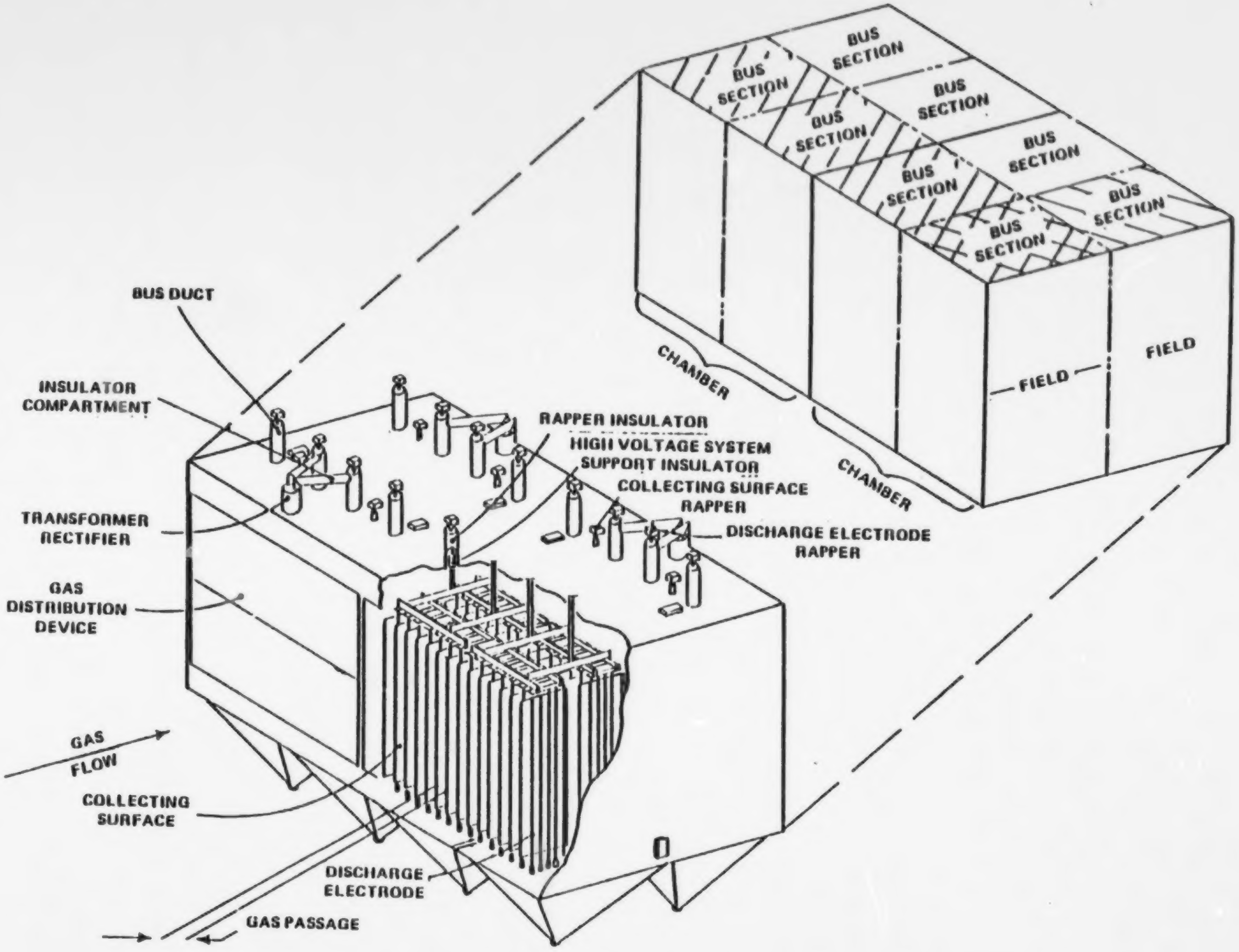
4.1.1.1.1 System. Particulate collection in an electrostatic precipitator occurs in three steps: suspended particles are given an electrical charge; the charged particles migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and the collected particulate matter is dislodged from the collecting electrodes.

Charging of the particles to be collected is usually caused by ions produced in a high voltage d-c corona. The electric fields and the corona necessary for particle charging are provided by high voltage transformers and rectifiers. Removal of the collected particulate matter is accomplished mechanically by rapping or vibrating the collecting electrodes. Figure 4.1-1 shows a typical cross-sectional view of an ESP.

4.1.1.1.2 Development status. Electrostatic precipitator technology is commercially developed and dates back to the early 1900's. The first successful application was made in 1907 when acid mist was collected at a sulfuric acid plant. ESPs have been used to control particulate emissions from coal-fired industrial and utility boilers since the early 1920's.[2] They are also the most commonly used collectors on utility oil-fired boilers.[3]

4.1.1.1.3 Applicability to industrial boilers. Electrostatic precipitation technology is applicable to a variety of types and sizes of industrial boilers. ESPs treating flue gas flow rates as low as 8500 m^3/hr (5000 acfm) are available.[4] Because of their modular design, ESPs can be expanded to treat flue gas from even the largest industrial boilers. ESPs have been installed on utility boilers with flue gas flow rates as high as 10,000,000 m^3/hr. Application of an ESP to an industrial boiler should have no adverse effect upon boiler operation. The fuel quality and its effect on particle characteristics is especially important and is discussed in detail in the next section.

4.1.1.2 Factors Affecting Performance. ESP collection efficiency is affected by a wide variety of factors related to the design of the ESP and the type of particles collected. Two factors have been specifically related to the overall collection efficiency through the Deutsch-Anderson equation:


BUS SECTION
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BUS SECTION
BUS SECTION
CHAMBER
CHAMBER
FIELD
FIELD
BUS DUCT
INSULATOR COMPARTMENT
RAPPER INSULATOR
HIGH VOLTAGE SYSTEM SUPPORT INSULATOR
COLLECTING SURFACE RAPPER
DISCHARGE ELECTRODE RAPPER
TRANSFORMER RECTIFIER
GAS DISTRIBUTION DEVICE
GAS FLOW
COLLECTING SURFACE
DISCHARGE ELECTRODE
GAS PASSAGE

Figure 4.1-1. Typical precipitator cross section.[1]

$$\eta = 1 - \exp(-WA/V)$$

where:

η = removal efficiency
W = migration velocity
A = plate area
V = volumetric flow rate

As indicated by this equation, ESP efficiency increases with increasing plate area relative to the gas flow rate and with increasing migration velocity.

Field data has indicated that the Deutsch-Anderson equation overpredicts collection efficiency. To account for the observed particle collection efficiencies, White proposes the empirical relationship,[5]

$$\eta = 1 - \exp[-(W_k A/V)^{0.5}]$$

as a more accurate predictor of efficiencies. The exponent of 0.5 is applicable for ESPs applied to coal-fired boilers. The term W_k is a measure of the effective migration velocity determined from experimental measurements.[6]

The following discussion reviews the major factors which influence ESP performance. For purposes of this discussion, the factors are grouped into two categories: (1) ESP design factors and (2) particle characteristic factors.

Design Factors. The specific collection area (SCA) is defined as the ratio of the total plate area to the gas flow rate and is usually expressed in terms of $m^2/(m^3/s)[ft^2/1000\ acfm]$. SCA is an important design and operating parameter. For a given application, collection efficiency improves as SCA increases. But for a given gas flow, the ESP also becomes larger and consequently more expensive as the SCA is increased. Thus, correct sizing of an ESP is important to both the performance and economics of its application.[21]

Typical relationships between precipitator collection efficiency and SCA are shown in Figure 4.1-2 for coal fly ash. The separate lines for different coal sulfur contents reflect the dependence of fly ash resistivity, and hence collection efficiency, on the coal sulfur content. Tests of low sulfur coals, for example, indicate that these variables may cause Figure 4.1-2 to underestimate the SCA needed for a 0.5 percent sulfur coal by 40 to 50 percent.[14] Practical values of SCA range from 328 to 2630 m^2/1000 m^3/min (100 to 800 ft^2/1000 acfm) for most field applications.[6]

The actual collection area during ESP operation depends on the flue gas flow rate which, for a particular boiler, is dependent on boiler load. The operating SCA increases as boiler load decreases, provided all ESP fields remain charged. Thus, the ESP must be designed to have the desired SCA at maximum boiler load where the flue gas flow is the highest.

The configuration and type of electrodes used in an ESP directly influence ESP performance. The electrode plate spacing, height, and length all influence the electrostatic forces exerted on the flue gas particles and thus influence the collection efficiency. Proper design of the ESP electrodes assures adequate residence time to allow the particles to migrate to a collection electrode.

Another key design variable is proper determination of the rapping cycle. If the cycle is too short, material that collects on the plates will not be compacted enough to settle to the bottom of the precipitation chamber and will be re-entrained. This re-entrainment can be minimized by proper design of collecting electrodes and rappers, minimizing rapping and rapping only a small section of the total precipitator plate area at a time. If the time between rapping is too long, however, the material on the collecting plates will become too thick and collection efficiency will be reduced. In addition, the rapping cycles must account for the differences in the amount of particulate matter collected in different ESP sections. ESPs typically use multiple sections in series. The section which treats the flue gas first will collect more particles than subsequent sections. The rapping cycles must be adjusted to insure each section is rapped only when the

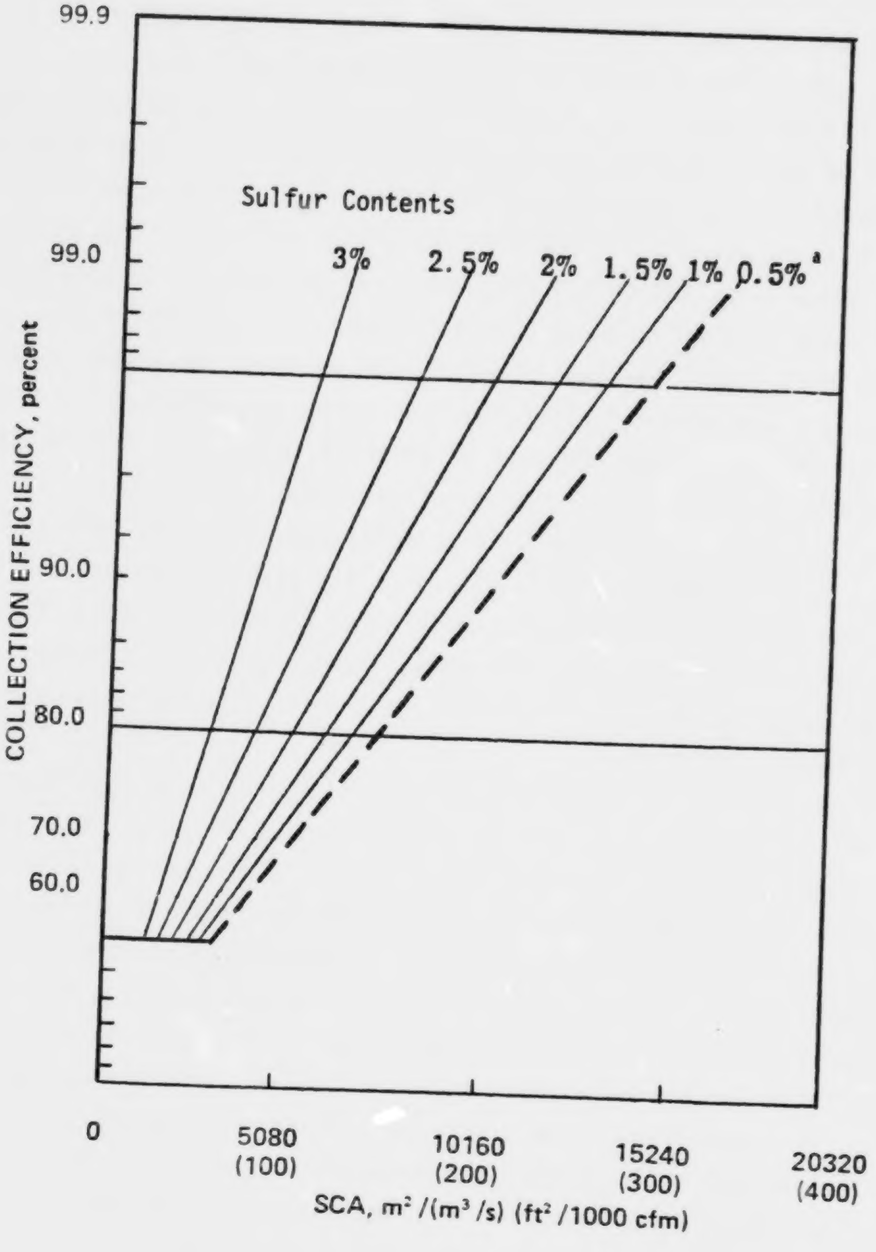

Figure 4.1-2. Relationship between collection efficiency and SCA for various coal sulfur contents. 14

[a] 0.5 percent sulfur values based on limited data.

collected material is the proper thickness. This necessitates more frequent cleaning cycles for the sections treating the raw flue gas.

Gas flow distribution also has a strong impact on ESP efficiency. Poor flow distribution between the collecting electrodes results in differing gas flow rates between each plate and therefore differing efficiencies for each section of the ESP. In addition, high velocities in the vicinity of hoppers and collecting electrodes can result in re-entrainment of collected dust. Another distribution consideration is the avoidance of flue gas flow through certain areas of the ESP. The construction of an electrostatic precipitator is such that nonelectrified regions exist in the top of the precipitator where the electrical distribution, plate support and rapper systems are located. Similarly, portions of the collection hopper and the bottom of the electrode system contain nonelectrified regions. Particulate-laden gas streams flowing through these regions will not be subjected to collection forces and will tend to pass through the precipitator uncollected.[20] Gas flow distribution problems can be corrected by proper inlet design, such as adding straighteners, splitters, vanes, and diffusion plates to the duct work before the ESP and by internal baffles and flow restrictors.

The voltage applied to the ESP electrodes is also an important factor affecting performance. Proper voltage assures an adequate corona for charging the particles while minimizing problems of sparking.[15] The use of automatic power supply control is desirable in many industrial boiler applications because of the varying fly ash and flue gas properties brought on by varying boiler loads and fuel properties. Automatic controls allow the ESP to respond more effectively to these changes by reducing sparking and current loss.[230]

Particle Characteristic Factors. The suitability of particulate collection by electrostatic precipitation depends on the resistivity of the particles. Particulates with resistivities in the range of 10^4 to 10^{10} ohm-cm have been shown by experience to be the most suitable for electrostatic precipitation. Particles with lower resistivities will give up their charge too easily and will be re-entrained in the gas stream.[16,17,18,19] Particles with higher resistivities will coat the collecting plates and will be hard to dislodge, thereby reducing the ability of the electrode to further collect particles. The resistivity of a given particle will vary with temperature and moisture. Typical variations in precipitation rate (which determines collection efficiency) with particle resistivity and coal sulfur content are shown in Figures 4.1-3 and 4.1-4.

The dependence of fly ash resistivity on fuel characteristics is very important when considering the application of ESPs to industrial boilers. The most notable fuel properties which affect the resistivity of the fly ash are the sulfur and alkali (primarily sodium) content. As shown in Figure 4.1-5, resistivity is altered favorable (reduced) with an increase in the sulfur content. As shown by Figure 4.1-6, an increase in the sodium content of the ash also tends to reduce the resistivity of the fly ash. Resistivity varies with temperature as well as fuel sulfur content as shown by Figure 4.1-7. The typical "cold side" ESP is located downstream of the air preheater, where the temperatures range from 380 to 448 K (240° to 350°F). A "hot side" ESP, on the other hand, is located upstream of the boiler air preheater, where temperatures range from 563 to 698 K (550 to 800°F).

Particle size distribution directly affects the precipitation rate parameter. Fractional collection efficiency data for ESPs applied to oil-fired boilers demonstrated ESP collection efficiencies of at least 99 percent for fine and coarse particles (less than 1 μm and greater than 10 μm), while collection efficiency dropped off from 99 to 89 percent for sizes between 1 and 10 microns.[10] In general, the fractional efficiency drop off for coal-fired boilers has been shown to occur in the range from 0.1 to 1 μm.[11] Figure 4.1-8 presents test results which show this for an ESP applied to a pulverized coal-fired boiler.[11] For this particular installation, fractional efficiencies vary from 99 to 90 percent for particles in the range of 2 to 0.1 μm.

Boiler load affects the particle size distribution for coal- and oil-fired boilers with reduced loads generally corresponding to reduced particle sizes.[12,13] Changing boiler load, and its effect on particle size

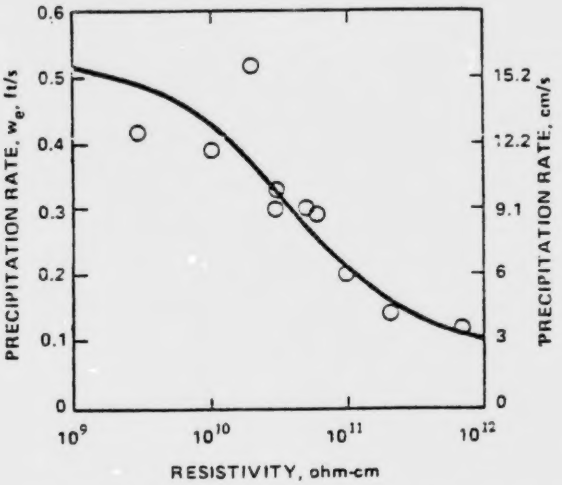

Figure 4.1-3. Precipitation rate versus particle resistivity.[7]

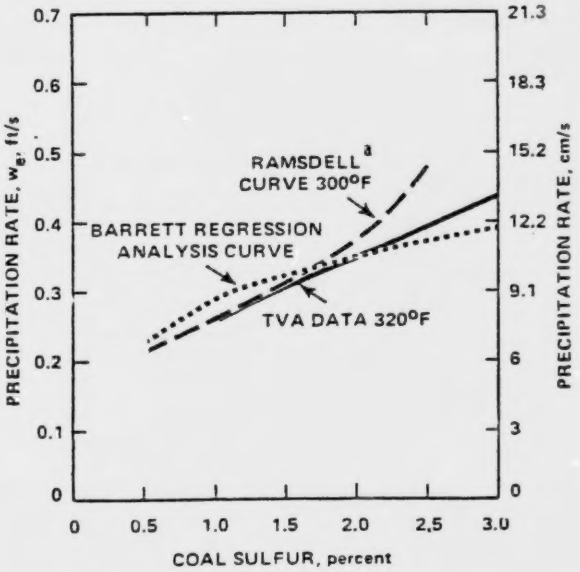

Figure 4.1-4. Precipitation rate versus coal sulfur percent.[8]

[a] Ramsdell number for sulfur percents above 2.5 have been disputed and are not included here.

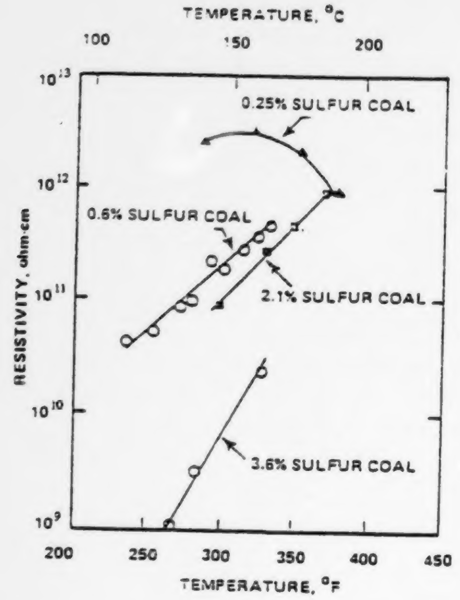

Figure 4.1-5. Variation of fly ash resistivity with temperature for coal of various sulfur contents.[9]

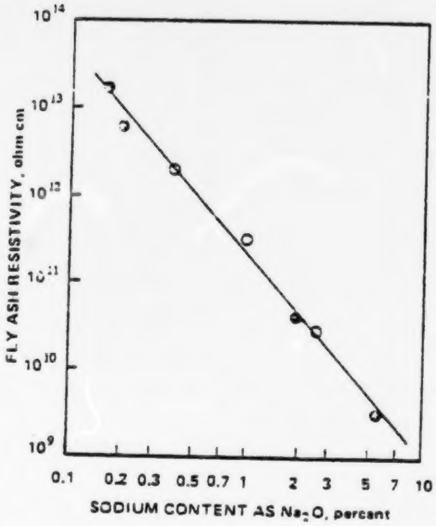

Figure 4.1-6. Variation of resistivity with sodium content for fly ash from power plants burning Western coals.[9]

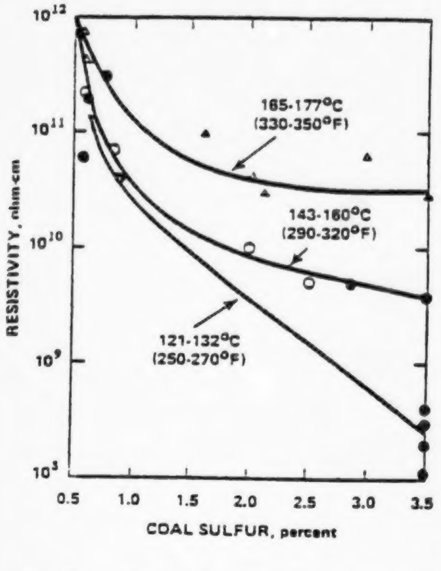

Figure 4.1-7. Fly ash resistivity versus coal sulfur content for several flue gas temperature bands.[9]

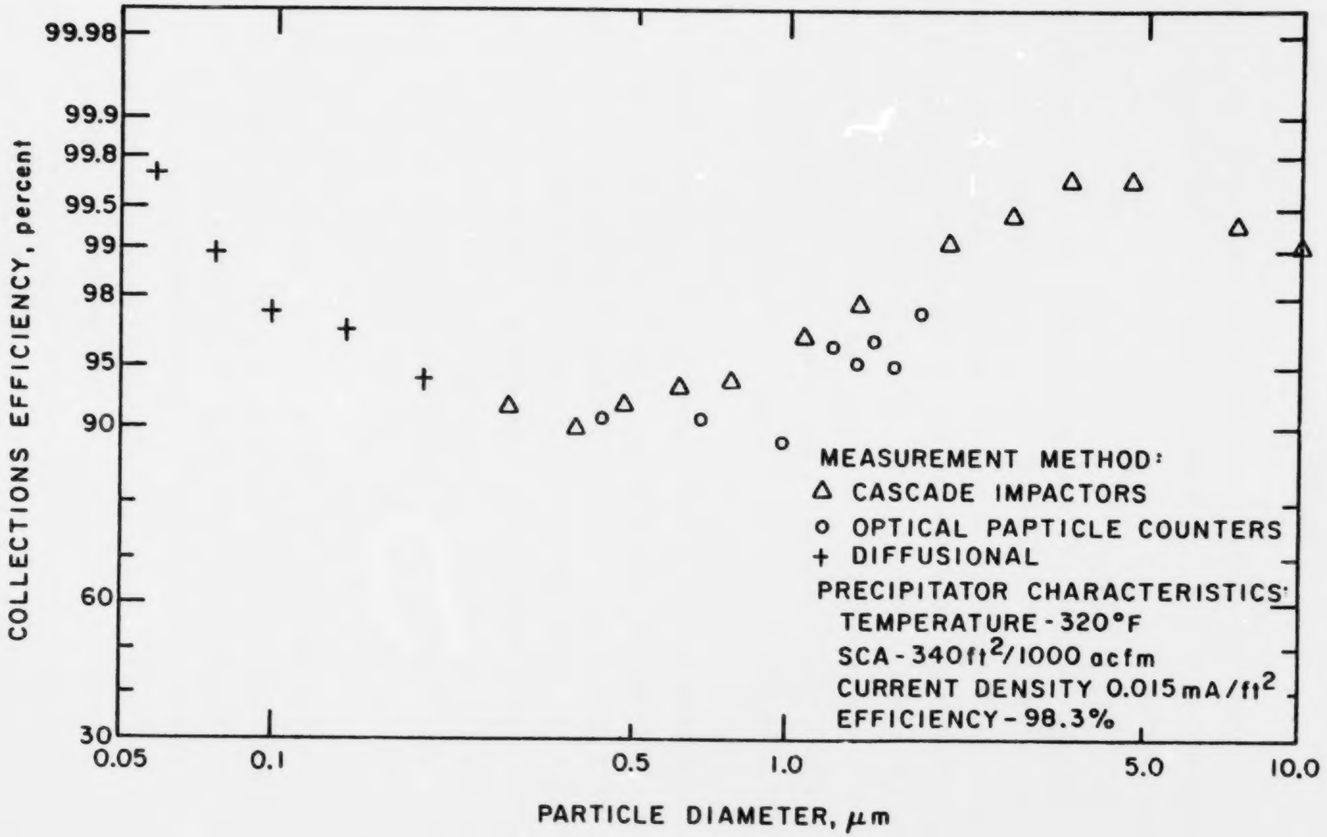

Figure 4.1-8. Measured fractional efficiencies for a cold-side ESP with operating parameters as indicated, installed on a pulverized coal boiler burning low sulfur coal.[11]

distribution may subsequently affect the overall collection efficiency of an ESP if not considered in the original design.

4.1.2 Fabric Filters

The collection mechanisms, design and operating parameters, development status, and applicability of fabric filters to industrial boilers are discussed in this section.

4.1.2.1 Process Description

4.1.2.1.1 System. A fabric filtration system (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure with dust hoppers. Particulate-laden gases are passed through the bags so that the particles are retained on the upstream side of the fabric, thus cleaning the gas. Typically a baghouse is divided into several compartments or sections. In larger installations an extra section is often provided to allow one compartment to be out of service for cleaning at any given time. A typical baghouse is shown in Figure 4.1-9.

The basic mechanisms available for filtration are inertial impaction, diffusion, direct interception, and sieving. The first three processes prevail only briefly during the first few minutes of filtration with new or recently cleaned fabric, while the sieving action of the dust layer accumulating on the fabric surface soon predominates. This is particularly true at high, >1 g/m^3 (0.437 gr/dscf), dust loadings. The sieving mechanism, in the case of coal fly ash filtration, leads to high efficiency collection unless defects such as pinhole leaks or cracks appear in the filter cake.[23]

In fabric filtration both the collection efficiency and the pressure drop across the bag surface increase as the dust layer on the bag builds up. Since the system cannot continue to operate with an increasing pressure drop, the bags are cleaned periodically. The cleaning processes used in coal-fired systems ordinarily consist of reverse-flow with bag collapse or mechanical shaking. These are sometimes used in combination with each other. Pulse-jet cleaning also has had considerable application while the reverse-jet concept (traveling blow ring) has not been widely applied.[24]

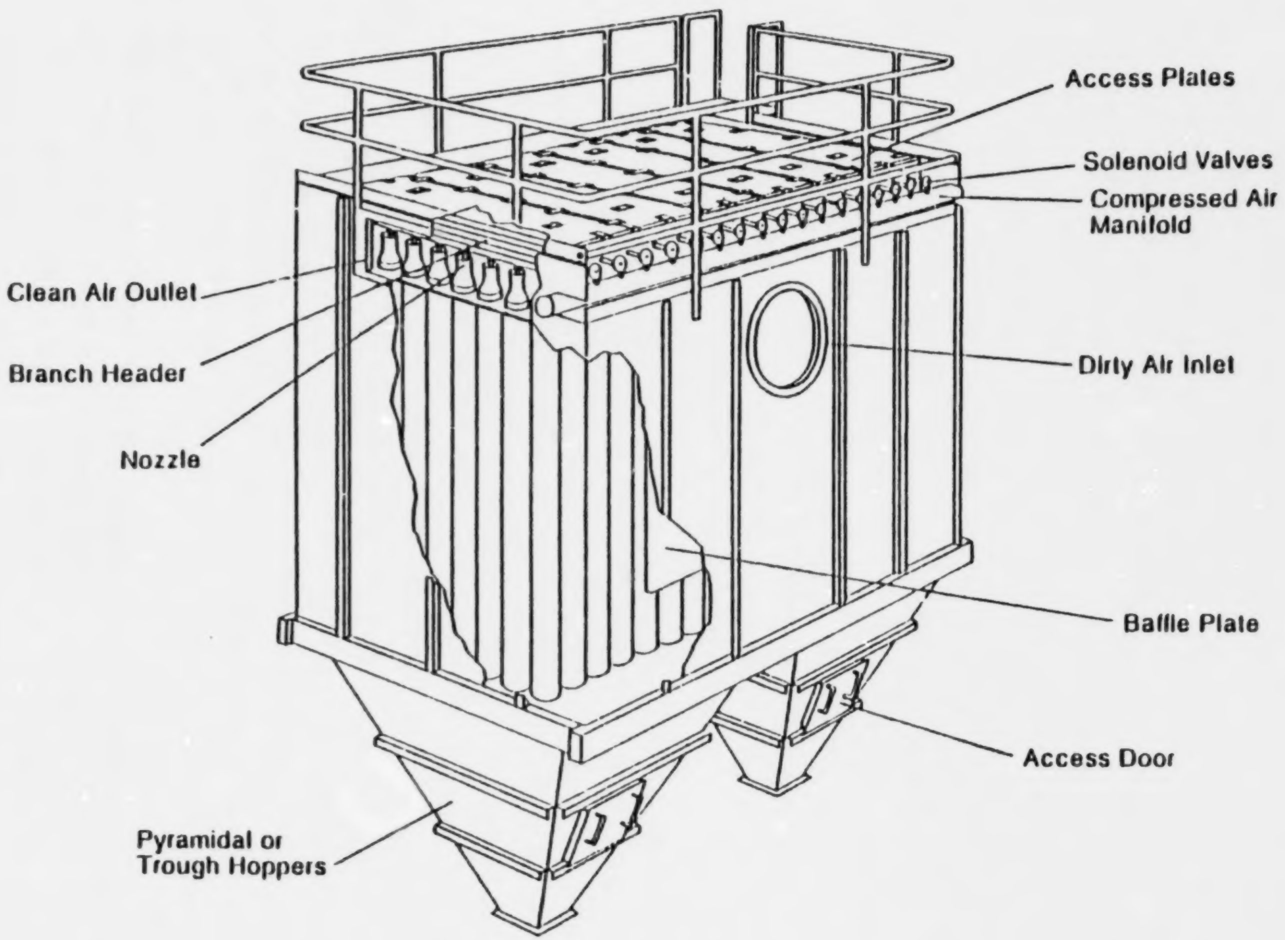
Access Plates
Solenoid Valves
Compressed Air Manifold
Clean Air Outlet
Branch Header
Nozzle
Dirty Air Inlet
Baffle Plate
Access Door
Pyramidal or Trough Hoppers

Figure 4.1-9. Isometric view of a pulse-jet fabric filter.[22]

4.1.2.1.2 Development status. Fabric filtration is a well-established technology with early industrial process applications dating back to the late 1800's. However, application to boiler flue gas has been a relatively recent development with the first successful installations designed in the late 1960's and early 1970's. Data published in December of 1979 shows that there were 104 industrial boilers at 61 locations either using, or planning on using fabric filtration systems for particulate emission control. These systems are summarized in Table 4.1-1. These boilers have flue gas rates ranging from 5940 to 1.5 x 10^6 m^3/hr (3500 to 900,000 acfm).[25]

4.1.2.1.3 Applicability to industrial boilers. Fabric filtration technology is applicable to various industrial boiler types as shown in Table 4.1-1. A possible limitation, however, is the application to oil-fired boilers. Large quantities of unburned carbon particles present in the flue gas of oil-fired boilers could cause difficulty in cleaning the dust layer from the bags.[26] Only a limited number of baghouses have been installed on oil-fired boilers. One installation initially experienced difficulty with bag life and plugging[3] and was later retired when changes in local air pollution control regulations forced a fuel switch to gas.

During baghouse operation it is essential that baghouse temperatures be maintained above the water and acid dewpoints of the gas so that condensation will not occur on the compartment walls and filter surfaces. In the case of condensation on filter surfaces, resultant plugging may restrict gas flow and cause irreversible bag damage. This is most likely to occur during transient operations such as startup, shutdown or fluctuating loads. Bypassing or preheating the baghouse prior to system startup, continuous gas recirculation during brief shutdowns, and sufficient insulation (7.6 cm or 3 inches of mineral wool or fiberglass) can prevent condensation problems.[27,28]

4.1.2.2 Factors Affecting Performance. Several factors can affect the performance of baghouse systems including air-to-cloth ratio, fuel properties, baghouse temperature and filter fabric and weave. These factors, and their affect on baghouse performance are discussed separately.

TABLE 4.1-1. BAGHOUSE INSTALLATIONS ON INDUSTRIAL BOILERS - U. S.[25]

Name/location	Manufacturer	Cleaning mechanism	Boiler firing method	Size (MW)$_e$	A/C*	acfm†	Startup date
1. Adolph Coors Co. Golden, Colo.	WF	RA, sa	PC	33	2.3/1	150,000	1976
2. Allied Chemical Southpoint, Ohio	WF	RA, sa	PC	(6)-12	2.99/1	59,000	1978
3. Allied Chemical Moundsville, W. Va.	WF	RA, sa	S	(4)-32	2.89/1	156,400	1978
4. Amalgamated Sugar Co. Nampa, Idano	WP	RA	PC	28	2.4/1	126,000	1974
5. Amalgamated Sugar Co. Nampa, Idaho	EB	Sh	PC	29	2.5/1	130,000	1975
6. Amalgamated Sugar Co. Nyssa, Oreg.	WF	RA, sa	S	21	3.56/1	92,000	1973
7. Amalgamated Sugar Co. Nyssa, Oreg.	WP	RA	PC	13	2/1	57,000	1975
8. Amalgamated Sugar Co. Twin Falls, Idaho	WP	RA	1-PC 1-S	21 each	2.5/1	100,000 each	1975
9. Ametek, Inc. Moline, Ill.	AAF	RA	S	9	4/1	40,000	1974
10. Ashland Chemical Co. Peoria, Ill.	SH	P	S	16	4.4/1	70,000	1976
11. Carborundum Co. Niagara Falls, N.Y.	CAR	RA	S	9	2/1	42,000	1967
12. Case Western Reserve U. Cleveland, Ohio	FK	Tbd	-	-	Tbd	Tbd	Tbd
13. Caterpillar Tractor Co. Decatur, Ill.	SH	POL	S	33	4.3/1	150,000	1976
14. Consolidated Rail Corp. Altoona, Pa.	WF	RA, sa	S	(3)-18	3.5/1	108,000	1978
15. Delco-Remy-Div. GM Anderson, Ind.	SH	P	S	(3)-9	3/1	24,000	1976
16. Denver Federal Center Denver, Colo.	ZU	RA	S	9	2.23/1	174,000	1978
17. E.I. DuPont Co. Cooper R, S.C.	WP	RA, va	S	20	1.9/1	90,000	1977
18. E.I. DuPont Co. Martinsville, Va.	WP	RA, va	PC	45	1.9/1	203,000	1977
19. E.I. DuPont Co. New Johnsonville, Tenn.	SH	P	S	(2)-29	4.4/1	130,000	1975
20. E.I. DuPont Co. Parkersburg, Va.	SH	P	S	(4)-50	4.4/1	221,000	1974
21. E.I. DuPont Co. Waynesboro, Va.	WP (test unit)	RA, va	PC	76	1.9/1	340,000	1977
22. Energy Development Co. Hanna, Wyo.	ICA	RA	S	5	2.5/1	24,000	1976
23. Formica Corp. Evendale, Ohio	WF	RA, sa	S	3	3.38/1	42,000	1978
24. Hammermill Paper Co. Lockhaven, Pa.	ICA	RA	S	53	2/1	150,000	1976
25. Hanes Dye and Finishing Winston-Salem, N.C.	DX	P	S	(2)-13	8.3/1	61,000	1975
26. Harrison Radiator- Division GM Lockport, N.Y.	WP	P	S	30	5/1	139,000	1974

TABLE 4.1-1. (Continued)

	Name/location	Manu-facturer	Cleaning mecha-nism	Boiler firing method	Size (MW)$_e$	A/C*	acfm†	Startup date
27.	Hiram Walker & Sons Peoria, Ill.	Tbd	Tbd	PC	60	Tbd	270,000	1978
28.	Keener Rubber Co. Alliance, Ohio	WF	P	Hdf	100 hp	4.36/1	5,500	1977
29.	Kerr Industries Concord, N.C.	ES (test unit)	Var	S	8	3-14/1	35,000	1974
30.	Kingsley Air Force Base Klamath Falls, Oreg.	SH	P	S	5	5/1	24,000	1976
31.	Long Lake Lumber Co. Spokane, Wash.	MP	P	HF	5	4.5/1	24,000	1973
32.	Lubrizol Corp. Painesville, Ohio	SH	P	OF	8	4.3/1	35,000	1974
33.	Monroe Reformatory Monroe, Wash.	ICA	Sh	S	3	2.8/1	11,000	1976
34.	Pennsylvania Glass Sand Corp. Union, Pa.	FD	P	PC	6	7/1	40,000	1972
35.	Republic Steel Warren, Ohio	WF	RA, sa	PC	35	3.34/1	275,000	1978
36.	Simpson Timber Co. Shelton, Wash.	SH	POL	HF	51	4.3/1	230,000	1976
37.	Sorg Paper Co. Middletown, Ohio	ZU	RA	PC	10	1.8/1	45,000	1972
38.	Uniroyal, Inc. Painesville, Ohio	SH	P	PC	9	2.6/1	42,000	1976
39.	Uniroyal, Inc. Mishawaka, Ind.	Tbd	Tbd	PC	22	Tbd	100,000	1977
40.	University of Illinois Chicago, Ill.	DV	P	OF	8	6/1	35,000	1976
41.	University of Iowa Oakdale, Iowa	ES	Tbd	-	-	Tbd	Tbd	Tbd
42.	University of Minnesota Minneapolis, Minn.	CAR	RA	S	20	2/1	90,000	1976
43.	University of North Carolina Chapel Hill, N.C.	WP	RA	-	(2)-6 each	Tbd	Tbd	1978
44.	University of Notre Dame South Bend, Ind.	WF (test unit)	P	S	1	7/1	3,500	1972
45.	Utah-Idaho Sugar Co. Moses Lake, Wash.	EB	Sh	S	22	2/1	98,000	1976
46.	U.S. Navy Hawthorne, Nev.	ICA	RA	S	21	1.7/1	96,000	1976
47.	U.S. Steel Co. Provo, Utah	WF	RA, sa	PC & gas	(3)-90	3.2/1	900,000	1977
48.	Westinghouse Electric Richland, Wash.	MP	RA	S	7	2/1	32,000	1976
49.	Westvaco Tyrone, Pa.	WF	RA, sa	S	20	3.26/1	135,000	1979
50.	Witco Chemical Bradford, Pa.	WF	RA, sa	1-S 1-PC	(2)-18	3.17/1	105,000	1978

TABLE 4.1-1. (Continued)

	Name/location	Manu-facturer	Cleaning mecha-nism	Boiler firing method	Size (MW)$_e$	A/C*	acfm†	Startup date
51.	General Motors Corp. Kettering & Norwood, Ohio Three Rivers, Mich. Warren, Ohio	SH	-	7-S	-	-	-	1979
52.	Scott Paper Co. Everett, Wash.	-	-	5-HF	-	-	260,000	1979
53.	Federal Bureau of Prions Fed. Correct. Institution Alderson, W.Va.	ES	-	S	-	2.6/1	16,000	1979
54.	Tennessee State Univ. Nashville, Tenn.	CE	RA	3-coal	-	-	50,000	-
55.	Georgetown Univ. Washington, D.C.	ES	-	FBC	-	5/1	43,000	-
56.	GSA, West Heating Plant Washington, D.C.	RC	P	2-S	-	-	-	1979
57.	West Point Pepperell, Inc. Opelika, Ala.	BS	-	coal	-	-	-	-
58.	U.S. Gypsum Co. Plasterco Plant Saltville, Va.	-	P	3-S	-	-	41,500	-
59.	AVTEX Fibers, Inc. Front Royal, Va.	EB	-	5-coal	-	-	600,000	March 1980
60.	Michigan State Univ.	RC	RA	2-PC	2-60	1.9/1	300,000	1980
61.	3-M Company St. Paul, Minn.	ICA	RA	2-S	2-14	2.2/1	70,000	1978

*A/C as given is in ft/min. To convert to m/min, multiply by 0.3048.

†To convert acfm to m^3/hr, multiply by 1.699

Manufacturers:

AAF - American Air Filter Co.
CAR - Carborundum Co. Pollution Control Div.
DV - DaVair Inc.
DX - Dustex, Sub. Amer. Precision Ind.
EB - Envirotech Corp. Buell Div.
ES - Enviro System Inc.
FD - Fuller Co., Sub GAIX
FK - Flex-Kleen - Sub. R.C.
ICA - Industrial Clean Air Inc.
ME - Menardi-Southern Div., U.S. Filter Corp.
MP - Mikropul Corp., Sub. U.S. Filter Corp.
SH - Standard Havens Inc.
WF - Wheelabrator-Frye Inc.
WP - Joy Mfg. Co Western Precip. Div.
ZU - Zurn Industries, Air Systems Div.
CE - CE Air Preheater
RC - Research-Cottrell
BS - Bahco Systems, Inc.

Symbols:

Hdf - Hand-fired
HF - Hogged fuel
OF - Oil-fired
P - Pulse
PC - Pulverized coal
Pol - Pulse, off-line
RA - Reverse air
RA, sa - Reverse air, shake assist.
RA, va - Reverse air, vibrator assist.
S - Stoker-fired
Sh - Shaker
Sp - Special
Tbd - To be determined
Var - Various
FBC - Fluidized Bed Combustion

Air to Cloth Ratio. The most important design and operating factor for a baghouse is the air-to-cloth ratio (A/C). This parameter relates the volume of gas filtered (m^3/min or acfm) to the available filtering area (m^2 or ft^2). The A/C ratio is, in effect, the superficial velocity of the gas through the filtering media. Air-to-cloth ratios typically range from 0.6 to 1.2 m/min (2 to 4 ft/min) for reverse-air cleaning systems and from 1.2 to 2.4 m/min (4 to 8 ft/min) for pulse-jet cleaning systems.[29] Emission tests have shown that fabric filter collection efficiency generally improves as the air-to-cloth ratio is decreased.[30] Since the air-to-cloth ratio is greatest at maximum flue gas flow (i.e., maximum boiler load), the fabric filter must be designed to operate at the desired air-to-cloth ratio at maximum boiler load. Operation at lower boiler loads will result in a lower air-to-cloth ratio and a collection efficiency equal to or greater than that at maximum boiler load (provided all fabric filter compartments are kept on line during reduced load operation to maintain the same available cloth area).

Fuel Properties and Baghouse Temperature. Variations in fuel properties are not as critical in fabric filtration as they are with ESP technology. However, fuel sulfur content dictates the flue gas SO_2 content and subsequent acid condensation temperature. The baghouse temperature must be maintained above the acid condensation point in order to reduce corrosion of the baghouse internals and ductwork in addition to reducing bag wear and destruction. This is especially important during start-up and shut-down operations when the temperature is most likely to fall below the acid condensation temperature. If acid condensation occurs after shutdown, the acid mist moisture eventually evaporates and crystallization on the bag filter may occur. In this situation, the bag filter may become brittle and subject to cracking when stress is once again applied.[28]

Bag Fabric and Weave. In general, bag material is chosen to withstand the specific flue gas environment expected to be encountered. Mechanical strength is also an important factor with respect to the mechanical demands exerted on the fabric by the gas flow and cleaning system. The bag material used in coal-fired boiler applications is usually fiberglass with a coating of silicone, graphite, and/or teflon.[24] Teflon coated felt bags are used in some pulse jet systems.

In general, although nonwoven fabrics (i.e., felt) are the most efficient particle collectors, they are the most difficult to clean. Texturized filament fabrics (i.e., teflon coated fiberglass) represent a middle ground in cleanability, durability and efficiency.[32]

Most fabrics are efficient in collecting a wide range of sub-micron particles. Emission tests conducted on a 63,100 kg steam/hr (139,000 lb steam/hr) spreader stoker equipped with a reverse-air fabric filter demonstrated that for particles in the 0.02 to 2 micron range, fabric filter fractional efficiency did not fall below 99.9 percent.[33]

4.1.3 Wet Scrubbers

The collection mechanism, status of development, applicability to industrial boilers, and factors which affect the performance of wet scrubbers for particulate control are discussed in this section.

4.1.3.1 Process Description

4.1.3.1.1 System. A wet scrubber is a collection device which uses an aqueous stream or slurry to remove particulates and/or gaseous pollutants. When scrubbing is applied for control of fly ash from combustion processes, the contactor used is usually one of the following types: gas-atomized spray scrubbers such as venturi and flooded disc scrubbers, fixed-bed absorbers such as sieve tray units, turbulent contact absorbers (TCA) or moving bed scrubbers and high pressure spray impingement scrubbers.[34]

There are three basic mechanisms involved with collecting particulate in wet scrubbers. These mechanisms include the interception, inertial impaction and diffusion of particles on droplets. The inertial impaction and interception effects dominate at large particle diameters, while the diffusion effects dominate at small particle diameters.

In a typical venturi scrubber, which is illustrated in Figure 4.1-10, the primary collection mechanisms are interception and impaction. Gas entering the venturi is smoothly accelerated in the converger until it reaches a maximum velocity in the throat. This converts the static pressure head to a kinetic energy head and typically requires from 1.2 to 5 kPa (5 to

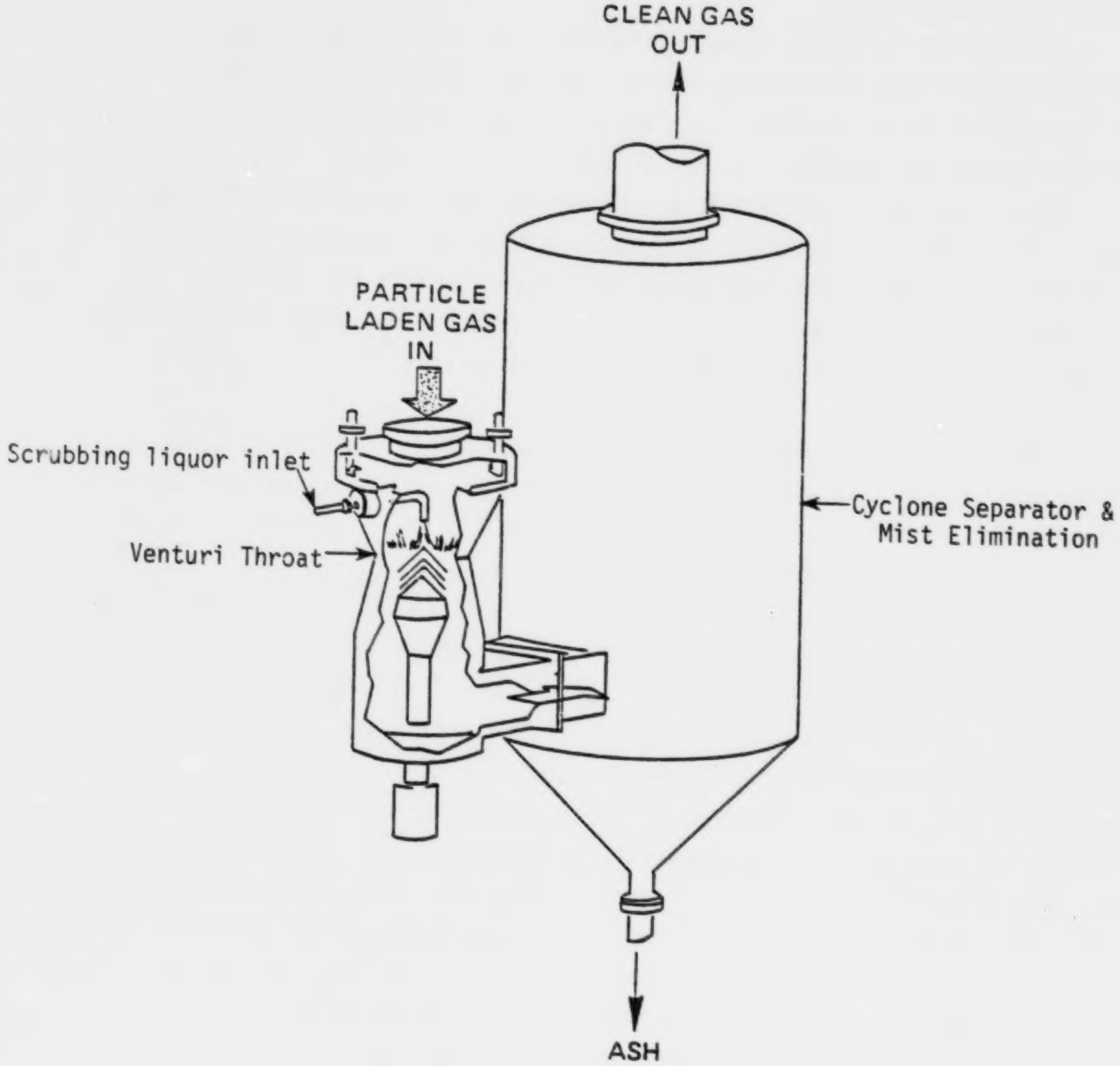
CLEAN GAS OUT
PARTICLE LADEN GAS IN
Scrubbing liquor inlet
Venturi Throat
Cyclone Separator & Mist Elimination
ASH

Figure 4.1-10. Variable-throat venturi scrubber.[35]

20 inches of water) pressure drop. Scrubbing liquid is atomized by the high velocity gas stream to produce droplet particles which act as targets for interception and impaction type collection.

In general, high interception and impaction collection efficiencies result from the high differential velocity between the gas stream and the atomized droplets created in the throat. Therefore, an increase in the system pressure drop will result in an increased differential velocity and subsequent increase in efficiency. Because system pressure drop is a function of energy expenditure, the energy imparted to the gas stream is a measure of the systems efficiency. The droplets are removed from the gas stream by centrifugal action in a cyclone separator and mist elimination section.[36] Variable throat venturi scrubbers are generally the favored type of scrubbers for particulate control since pressure drop can be maintained at constant levels across a wide range of boiler loads.

Sulfur content of the boiler fuel is important not as it affects collection efficiency, but from a corrosion standpoint. Recirculation of a low pH (pH less than 3) liquor has resulted in corrosion problems in particulate scrubbers. Low slurry pH results from the absorption of acidic species (e.g., SO_2, SO_3 and HCl) from the flue gas. Consideration must therefore be given to the construction materials used in the contactor. Fiberglass reinforced polyester or rubber-lined steel are the most common materials used. These materials are also resistant to the errosive effects of the slurries which must be handled in wet scrubbing systems.

A common operating technique used to prevent low pH conditions is the addition of an alkali compound. The addition of an alkali compound to the wet particulate scrubber for pH control results in the recirculation of a scrubbing slurry with sufficient dissolved alkalinity to absorb significant amounts of SO_2 from the flue gas, thus forming a combined particulate matter/SO_2 removal system. For example, if sodium carbonate (Na_2CO_3) is used as the chemical for pH neutralization, the overall chemical reaction that occurs is the following:

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (4.1.3\text{-}1)$$

If sufficient alkalinity is added to the scrubbing liquor, then high SO_2 removals can be achieved. Flue gas desulfurization processes are described in Section 4.2.

4.1.3.1.2 Development status. Particulate control by wet scrubbing is a well-established technology. The use of wet scrubbers in Great Britain for cleaning boiler flue gases dates back to 1933. However, this technology has only been adapted within the last 10 to 20 years to control fly ash emissions from power boilers in the U. S. Since the early 1960's, wet scrubbing has been applied to fossil fuel-fired boilers in the U. S. for combined particulate collection and SO_2 absorption.[37]

4.1.3.1.3 Applicability to industrial boilers. Wet scrubbers are applicable to both coal- and oil-fired industrial boilers. The two major considerations in their use are (1) fuel sulfur content and (2) disposal of a wet sludge versus a dry product as collected by ESPs, fabric filters, or mechanical collectors. The sulfur content of the fuel can impact the use of a wet scrubber in two ways: if no SO_2 removal is desired the use of a wet scrubber on high sulfur fuel-fired units will require that the scrubber be constructed of a high quality corrosion-resistant material. However, if SO_2 removal is required the wet scrubber can serve as the single control device for both SO_2 and particulate, thus reducing the total cost of add-on controls over a wet scrubber for SO_2 removal and a fabric filter or ESP for particulate control.

The chloride content of the coal is also important. Chloride build-up in the scrubbing liquor, resulting from absorption of chloride species present in the flue gas, can result in low pH liquor with potential stress corrosion of the scrubber vessel.

4.1.3.2 Factors Affecting Performance. Factors that affect scrubber performance include:

- scrubber design
- liquid-to-gas ratio (L/G)
- gas velocity
- energy consumption
- particle size distribution

- particulate loading at the inlet to the scrubber
- construction materials
- collection of wetted particles by cyclones and mist eliminators

Scrubber design has an important effect on the amount of particulate matter that can be removed from the gas stream. Of the several general scrubber types (plate tower, packed tower and venturi) plate towers and venturis are the best choices for particulate removal. Packed towers are not generally well-suited to particulate removal. Multiple plate towers are effective in removing particulate matter over 1 micron in diameter, but venturi scrubbers are more effective than plate towers on submicron particles. Plate towers do not resist plugging and scaling as well as venturis do, but the use of a mechanical collector to remove the bulk of the fly ash particles upstream of the scrubber can help alleviate these problems. Plate towers are well equipped to handle the high liquid rates and greater residence times that might be required for simultaneous SO_2 control.

Several features of venturi scrubbers make them a practical choice for particulate removal by wet scrubbing:

- high particulate removal capability,
- relatively low scaling potential, and
- easily controllable pressure drop.

Venturi scrubbers generally consume more electrical energy than plate towers.

Although the performance of a venturi scrubber depends directly on both the L/G and the gas velocity past the droplets, the gas phase pressure drop is the major factor influencing particulate matter removal.[38] As shown by Figure 4.1-11, fractional removal efficiency increases with increasing gas phase pressure drop and subsequent increasing energy expenditure.

For this reason, venturi scrubber applications generally include a variable throat system (enabling control of pressure drop) to allow a constant efficiency to be maintained at varying boiler loads.[37] Pressure drops across venturi scrubbers generally range from 1.5 to 30 kPa (5 to 100 in w.g.) depending upon the application and the desired removal

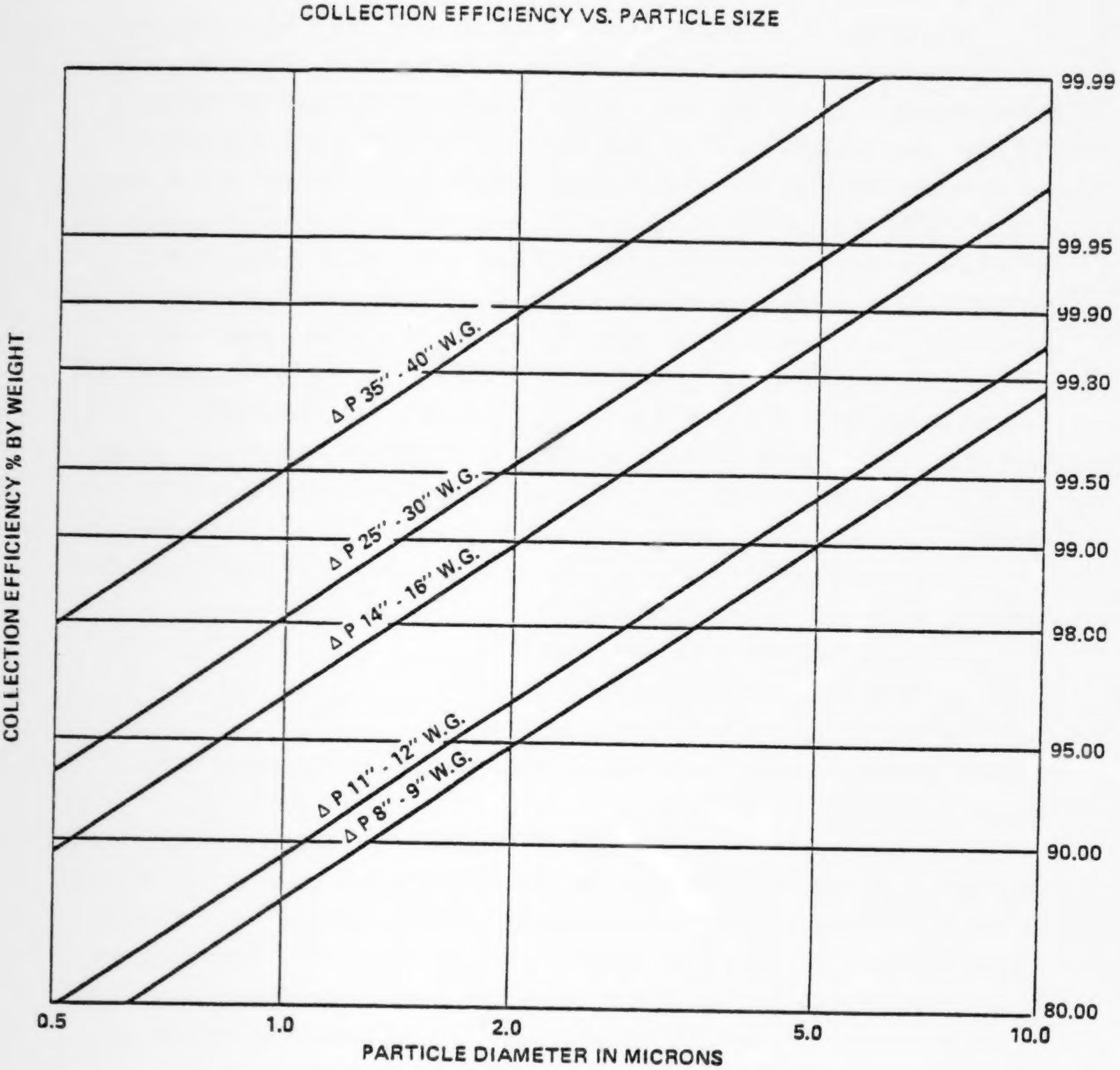

Figure 4.1-11. Venturi scrubber comparative fractional efficiency curves.[39]

efficiency. The emissions data for venturi scrubbers presented later in this chapter show that pressure drops range from about 2.4 to 5.0 kPa (8 to 20 in w.g.) for applications on coal-fired industrial boilers. In general, gas velocities through the venturi throat range from 61 to 183 m/s (200 to 600 ft/s) while liquid-to-gas ratios (L/G) vary from 1.0 to 2.0 liters/m^3 (8 to 15 gal/1000 ft^3).[40] At gas-side pressure drops of less than 5.0 kPa (20 in w.g.), good initial liquid distribution is important to achieving high particulate collection efficiencies.[38]

The collection efficiency of a venturi scrubber decreases when the size of the particles to be collected is in the submicron range.[41] Thus it is important to take the size distribution of the particles to be removed into account when designing the scrubber. Figure 4.1-12 demonstrates the relationship between aerodynamic cut diameter and the pressure drop, with the liquid to gas ratio as a parameter. The aerodynamic cut diameter is the particle size that is collected with an efficiency of 50 percent by a device such as an Anderson, Pilot, or Brinks impactor. Figure 4.1-11 also illustrates the relationship between wet scrubber performance and particulate size distribution at constant gas-side pressure drop.

In a plate tower, an effective way of increasing particulate removal is to increase the velocity of gas through the plates (trays). Adding trays does not necessarily improve particulate removal, but increasing the pressure drop across a single tray does.

The transient, nonsteady state periods of industrial boiler operation are critical in terms of the control system's performance. Variations in temperature, airflow, and particulate loadings which affect system performance are typical of the varying load conditions often encountered with industrial boilers.[40] However, with a system designed for maximum load and particulate loading, outlet emissions during low or transient load conditions will be less than the design emission rate.

4.1.4 Multitube Cyclones

The collection mechanism, status of development, applicability to industrial boilers, and factors which affect the performance of multitube cyclones are discussed in this section.

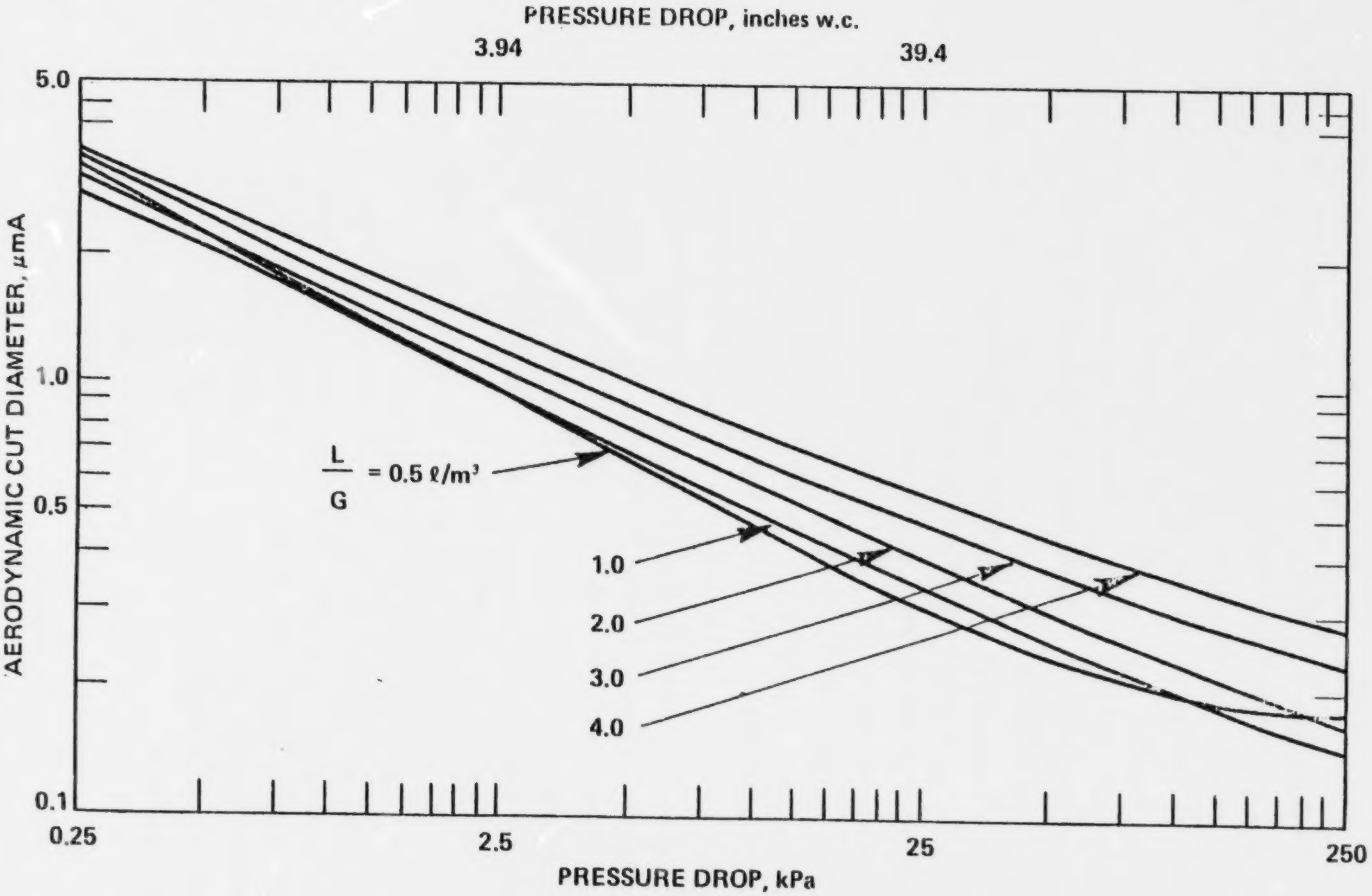

Figure 4.1-12. Aerodynamic cut diameter versus gas pressure drop with liquid-to-gas ratio (L/G) as a parameter.[41]

4.1.4.1 Process Description

4.1.4.1.1 System. Cyclones are mechanical collectors which remove particulates from a gas stream by an inertial impaction mechanism. At the entrance of the cyclone a spin is imparted to the particle-laden gas. This spin creates a centrifugal force which causes the particulate matter to move away from the axis of rotation and towards the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to a dust collection hopper where they are deposited.

In a typical single cyclone the gas enters tangentially to initiate the spinning motion. In a multitube cyclone the gas approaches the entrance axially and has the spin imparted by a stationary "spin" vane that is in its path. This allows the use of many small higher efficiency cyclone tubes, with a common inlet and outlet, in parallel to the gas flow stream. Figure 4.1-13 illustrates the configuration of the individual tube and an assembly of such tubes in a multitube cyclone.

One variation of the multitube cyclone is two similar mechanical collectors placed in series. This system is often referred to as a dual or double mechanical collector. The collection efficiency of the dual mechanical collector is theoretically improved over that of a single mechanical collector.

4.1.4.1.2 Development status. Fly ash collection by multitube cyclones is a well established technology. It has been used for many years to limit particulate emissions from coal-fired industrial and utility boilers and to reduce erosion of downstream ductwork and equipment. Multitube cyclones were the most common type of mechanical collector used for fly ash control before more stringent emission regulations were enacted. However, in many cases they now function as precleaning devices to reduce grain loading to the primary collection device.[43]

4.1.4.1.3 Applicability to industrial boilers. Because of their modular configuration, multitube cyclones are applicable to all sizes of coal- and oil-fired industrial boilers. There are several operational factors associated with industrial boilers that affect mechanical collector

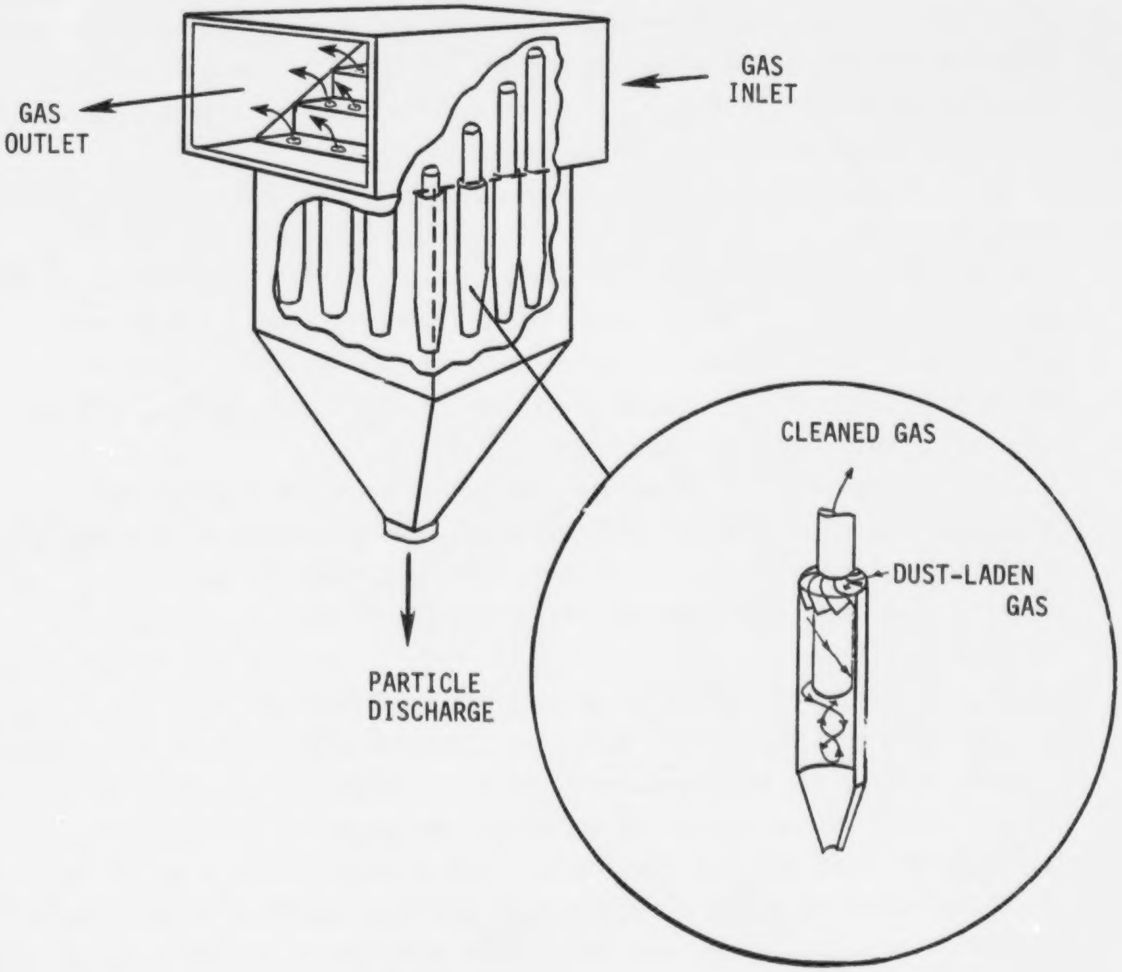
GAS INLET
GAS OUTLET
CLEANED GAS
DUST-LADEN GAS
PARTICLE DISCHARGE

Figure 4.1-13. Schematic of a multiple cyclone and detail of an individual tube.

performance and limit applicability as the sole PM control device. These and other factors are discussed in the next section.

Application of the dual mechanical collectors is currently limited to a few coal-fired boilers operating under relatively steady steam demand conditions.

4.1.4.2 Factors Affecting Performance. The most important design factors affecting performance for a cyclone are the inlet gas velocity, the diameter of the tubes, the number and angle of axial vanes, the construction materials, and the system pressure drop. Most multitube cyclones are axial-gas entry units designed for gas velocities of 25.4 to 35.6 m/sec (5,000 to 7,000 ft/min) in the entry vane region. Such high velocities require the use of hard alloy materials for the vanes (gray or white iron or chromehard steel) to minimize vane erosion.[45] Figure 4.1-14 is a theoretical curve that presents the variation of the collection efficiency resulting from the variation of the inlet gas velocity.

The performance of any mechanical collection system is significantly affected by the particle size distribution of the particulate matter to be collected. Figure 4.1-15 shows that the collection efficiency of a cyclone increases as the percentage of larger particles increases. Particle collection efficiency for most cyclonic devices varies inversely with the diameter of the collecting tube. A reduction in tube diameter increases the radial force acting upon the particles so that their transit to the wall region and their removal is accelerated.[45] Figure 4.1-15 illustrates comparative collection efficiencies for two axial-entry cyclones with diameters of 15.2 and 30.5 cm (6 and 12 inches), respectively, as a function of the percent of dust under 10 μm.[48]

Operational procedures related to the boiler/control device system that hamper mechanical collector performance include transient operations such as startup, shutdown, or emergency upsets and load variation.[44] In addition, air in leakage, cyclone corrosion, particle reentrainment, tube plugging, pressure drop and the degree of flyash reinjection will affect mechanical collector outlet emissions.[117] Large load swings significantly affect removal efficiency. Changes in the sulfur content can alter the acid

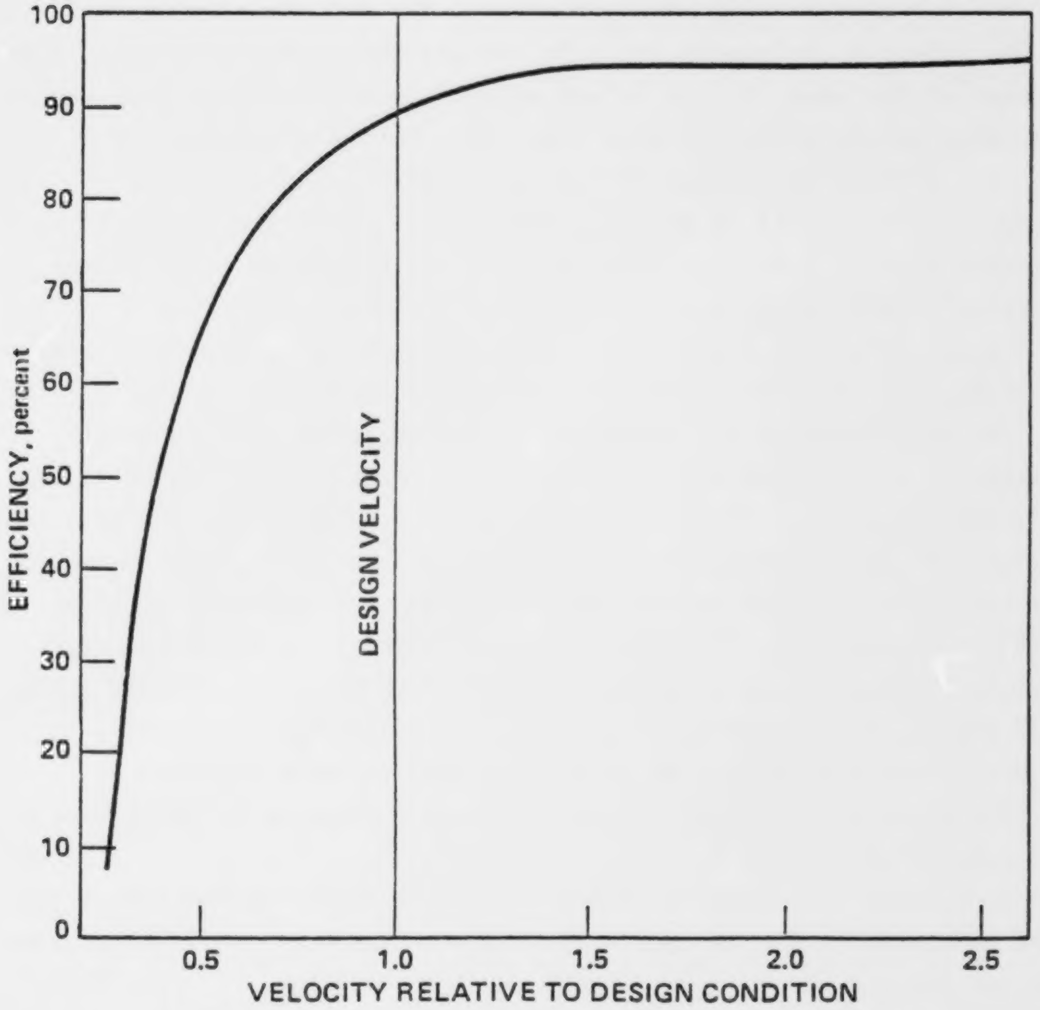

Figure 4.1-14. Variation of a single cyclone collection efficiency with gas velocity.[46]

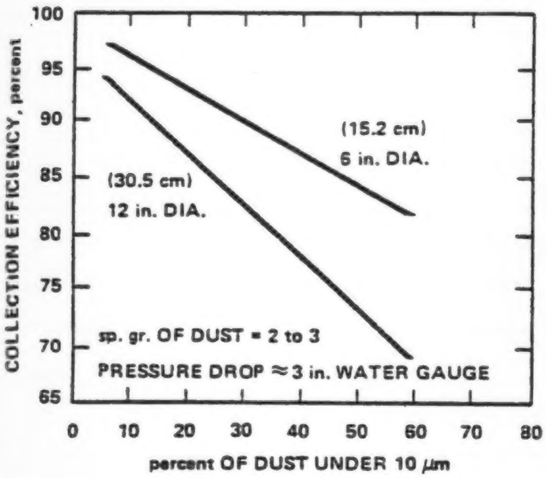

Figure 4.1-15. Typical overall collection efficiency of axial-entry cyclones.[48]

concentration in the flue gas which can result in corrosion of the cyclone. At constant load and inlet particle size distribution, outlet emissions will be proportional to inlet mass loading. Therefore, a large increase in fly ash loading (which could result from variations in load, coal ash content, soot blowing or fly ash reinjection) will increase emissions.

Proper mechanical collector maintenance is essential in sustaining the desired removal efficiency. To avoid efficiency losses due to corrosion of the cyclone from acid condensation or particle abrasion, the cyclone should be constructed of materials that will withstand the highest expected loading of potentially corrosive flue gas components. Primary considerations to be used in evaluating the construction materials needed are:[44]

- Gas temperature
- Abrasiveness of the dust particles
- Corrosiveness of the gas stream

If the gas stream is corrosive or the dust particles are abrasive it may be necessary to use a stainless steel alloy instead of carbon steel in the construction of the cyclone.

It is important to accurately monitor the pressure drop across the cyclone so that any plugging can be detected. In addition, the interior should be inspected on a regular basis for corrosion damage, plugged tubes, or defective gaskets. Another area of maintenance that is critical to efficient mechanical collector performance is the discovery and remedy of air leakage into the collector. Leakage can occur at the hopper access door, hopper discharge valve, hopper casing, or the lower tube sheet. Air leakage into a collector hopper can result in reentrainment of collected particles, thus reducing collector performance.

One of the most detailed sources of information on mechanical collector performance is a study conducted jointly by the American Boiler Manufacturer's Association (ABMA), the Department of Energy (DOE), and EPA. Several stoker-fired boilers equipped with mechanical collectors were tested in this study and particulate emissions tests were conducted at both the boiler and the mechanical collector outlets. Based on a review of these data, the following conclusions can be made about the effect of boiler operating parameters on mechanical collector performance:[47]

- Figure 4.1-16 shows that, for 3 similar coals, mechanical collector efficiency remained relatively constant with changes in boiler load above about 60 percent. However, there was significant drop in collector efficiency at loads of approximately 50 percent and less.

- There was considerable scatter in the test data for some units as a result of variable process conditions and fuel types. However, the results showed that particulate matter emissions from both the boiler and mechanical collector (in terms of lb/10^6 Btu) tended to increase as the boiler load increased. This trend can be seen in Figures 4.1-17 and 4.1-18 where boiler and mechanical collector outlet emissions are plotted as a function of boiler load.[231] Although these figures illustrate emissions from a single boiler, they are representative of the overall trends from the data set.

- Figures 4.1-18 also illustrates that controlled emissions from this boiler remained fairly steady, but showed a trend of increased emissions at boiler loads greater than 50 percent. This trend was also seen for other boilers. The sharp increase in emissions at very low loads was attributed to the reduced mechanical collector efficiency at the unusually low firing rate obtained at this one site.

- In general, no significant correlations were observed between mechanical collector performance and overfire air levels, or excess air levels.

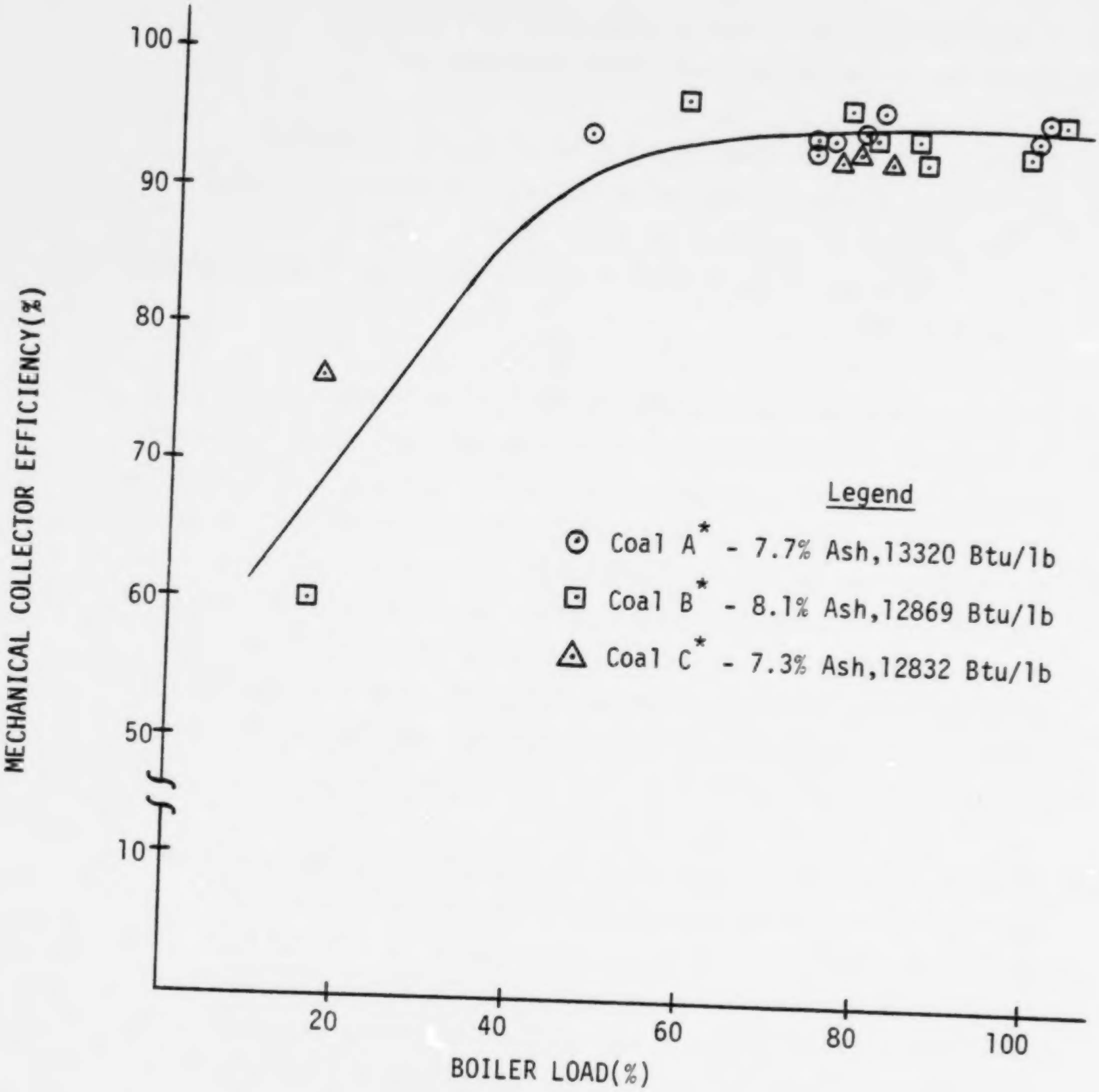

Figure 4.1-16. Mechanical collector efficiency versus boiler load (spreader stoker boilers).[47]

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*Note: Data shown is from two different boiler collector systems. Coal A was fired in one, while coals B and C were fired in the other .

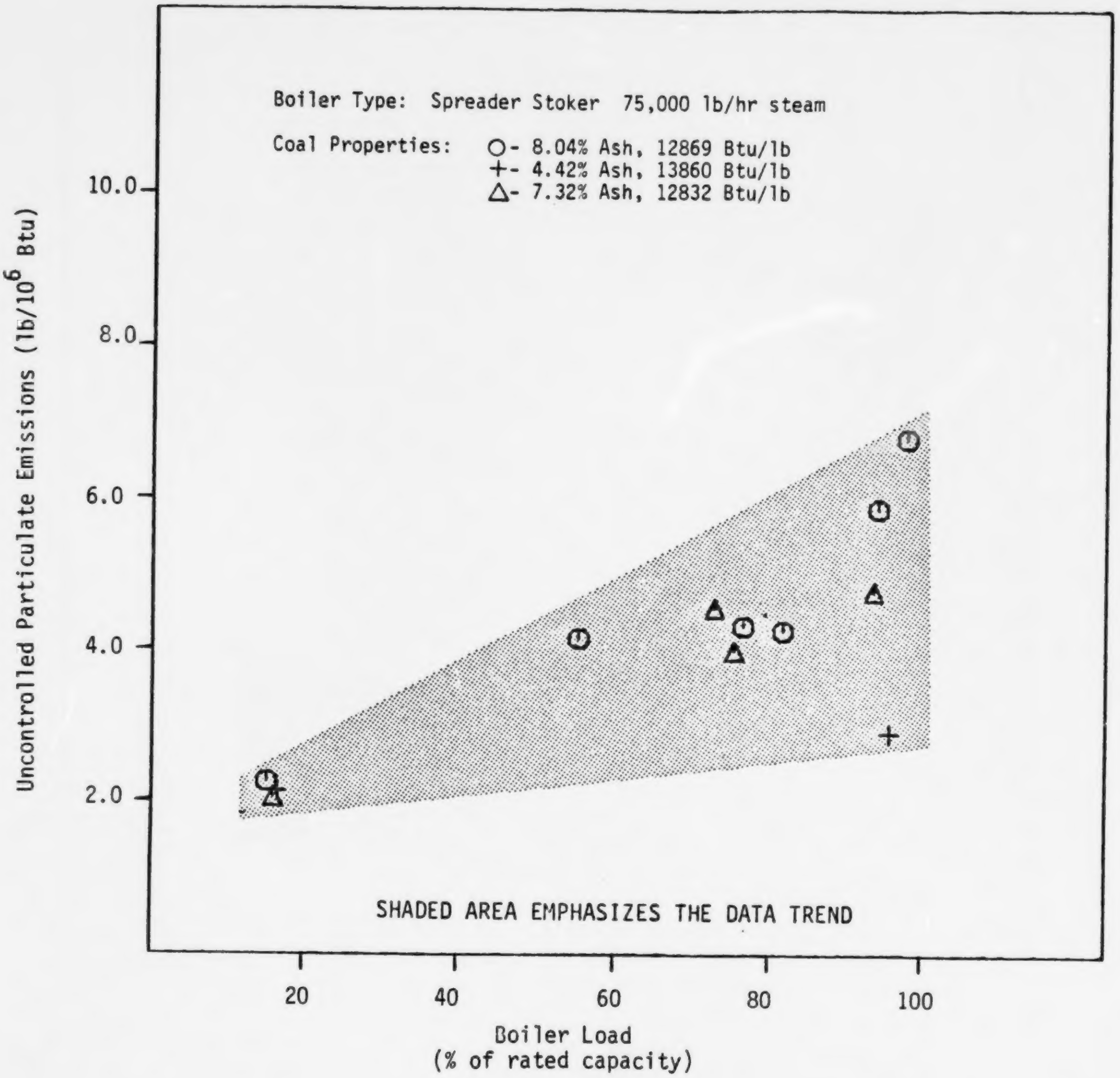


Figure 4.1-17. Uncontrolled particulate emissions vs. boiler load.[231]

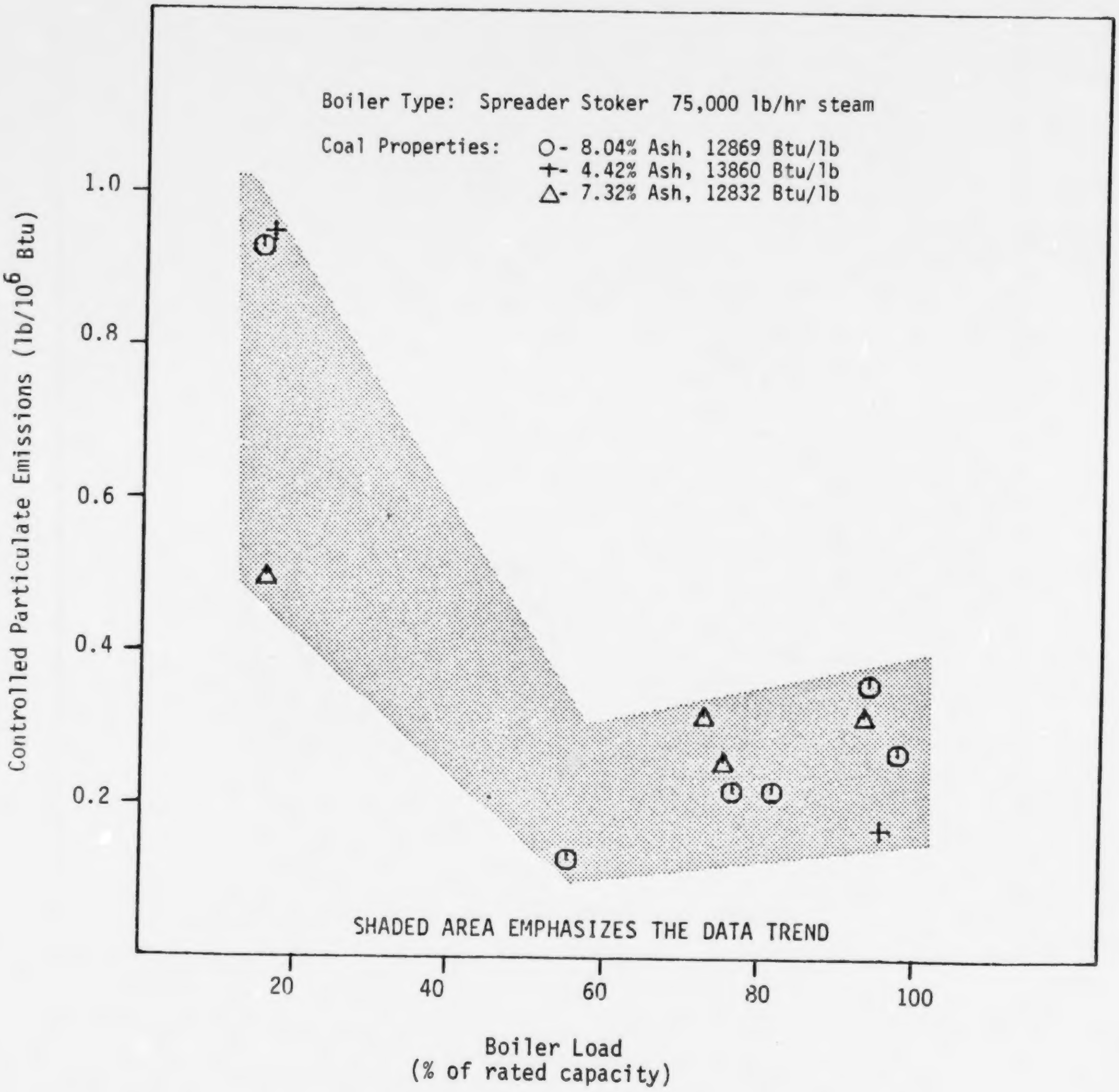


Figure 4.1-18. Controlled particulate emissions vs. boiler load.[231]

- The data did show that mechanical collector collection efficiency was lower when there were relatively high percentages of small particles (less than 10 microns in diameter) at the inlet to the collector. However, no correlations were observed between boiler load, excess O_2, or overfire air levels and the resulting particle size distribution.

4.1.5 Side Stream Separator

The collection mechanism, status of development, applicability to industrial boilers, and factors which affect the performance of side stream separators are discussed in this section.

4.1.5.1 Process Description

4.1.5.1.1 System. The side stream separator system consists of a single multitube cyclone and a small pulse-jet baghouse as shown in Figure 4.1-19. The boiler exhaust stream is ducted to the cyclone where a portion (approximately 15 to 40 percent) of the gas is drawn from the cyclone at the bottom of the tubes just above the ash hopper and ducted to a fabric filter. The gas flow from the cyclone and baghouse are then recombined and exhausted to the stack. The gas stream from the cyclone to the baghouse is believed to have a higher concentration of small particles relative to the total gas stream thereby removing the particles of the size that are generally not collected efficiently by the mechanical collector alone.[50]

As individual units, the cyclone and fabric filter operate as described in Sections 4.1.2 and 4.1.4. Together, the fabric filter adds additional overall removal of particulate to the cyclone thereby improving overall removal efficiency. The side stream separator design is based on the use of a single- or multi-compartment pulse-jet fabric filter.

4.1.5.1.2 Development status. The side stream separator system is a recent development in particulate removal from industrial boilers. Its application is currently limited to retrofitting existing mechanical collectors on spreader stokers firing a limited range of coal types. As a result, the existing data base for side stream separators is limited. In

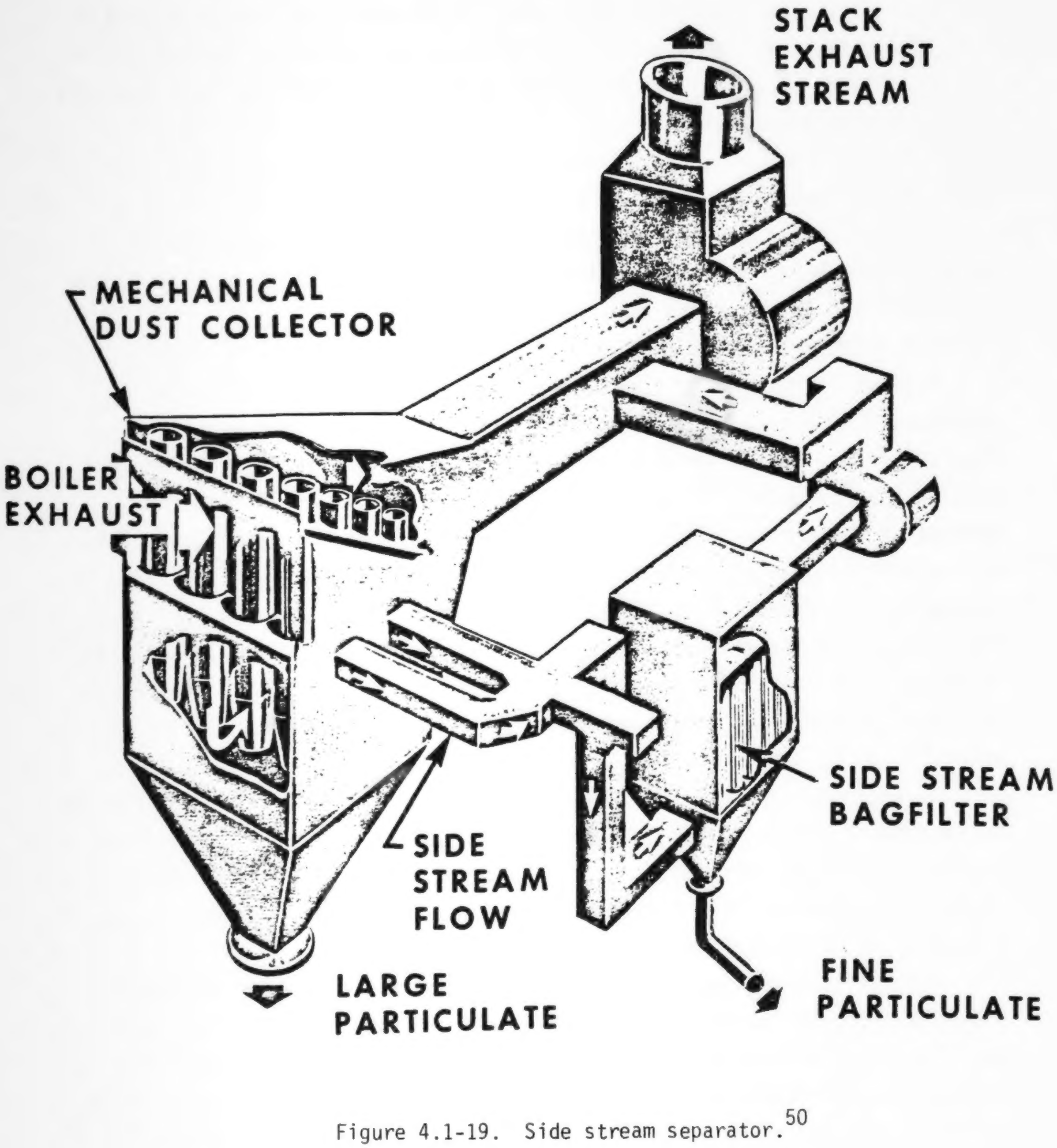

STACK EXHAUST STREAM
MECHANICAL DUST COLLECTOR
BOILER EXHAUST
SIDE STREAM BAGFILTER
SIDE STREAM FLOW
FINE PARTICULATE
LARGE PARTICULATE

Figure 4.1-19. Side stream separator.[50]

addition, because the existing installations are relatively new, the long term performance of side stream separators cannot be documented. There are currently 2 to 3 vendors and an independent consultant offering similar devices as retrofits to upgrade existing mechanical collector performance. However, vendors do not offer performance guarantees on this device.

4.1.5.1.3 Applicability to industrial boilers. The side stream separator is applicable to coal-fired stoker boilers, but has not been applied to pulverized coal units. Application of this technology is currently limited to spreader stokers firing low or medium ash coals ($\leq$10 percent). Application of this device to other stoker types and coal types has not occurred to date.

4.1.5.2 Factors Affecting Performance. Most of the factors that affect performance of mechanical collectors and fabric filters (previously discussed in Sections 4.1.4 and 4.1.2, respectively) also affect the performance of the side stream separator. The performance of the mechanical collector is affected by the diameter of the tubes, the number and angle of entry vanes, construction materials, and pressure drop. Fabric filter performance is affected by air-to-cloth ratio, filter fabric, cleaning mechanism, baghouse temperature and fuel properties.

The performance of mechanical collectors is also affected by the proportion of small fly ash particles (less than 10 microns in diameter) at the inlet to the collector. However, this factor should have less impact on side stream separators since the fabric filter used with the mechanical collector is relatively efficient with respect to fine particles.

As discussed in Section 4.1.4, mechanical collector efficiency drops off rapidly at low boiler loads. This factor will result in decreased side stream separator efficiency at low loads, unless uncontrolled emissions at low loads are reduced enough to compensate for the reduced efficiency.[49] Currently, side stream separators are equipped with constant flow rate fans. Therefore, as boiler load decreases a higher percentage of the total flow is routed to the side stream baghouse. This affect may act to compensate for reduced mechanical collector efficiency at low loads. However, present data are insufficient to adequately assess the performance of sidestream separators at lower loads.

4.1.6 Emission Data

Available emission data for ESPs, fabric filters, wet scrubbers, multitube cyclones, and side stream separators are presented in this section. The sites from which this test data were gathered are referred to here as Plant A, B, C, D, etc. A description of each test site including the particulate control equipment tested, the complete test data, and any unusual emission testing or control device operational factors that impact the validity of the test results are presented in Appendix C. Appendix C also contains the references for complete test reports on each site.

The data base gathered during the course of this study was reviewed extensively to assure that each test met two important criteria. First, all of the PM emission tests were reviewed to determine if the test methods complied fully with EPA Method 5 specifications. Those data found to have been collected with emission test methods not meeting Method 5 specifications have not been included in this chapter or Appendix C.

Secondly, a thorough analysis of the remaining valid test data was conducted to assure that no unusual boiler or control device operating conditions affected the test results. The data was also evaluated in an effort to characterize, as fully as possible, the important design and operating parameters of each emission control system. Emission test data collected under nonrepresentative conditions or data collected from systems where critical control device design and operating parameters could not be documented are generally not presented in this section. Exceptions to this procedure were made in a few cases, however. Test data that can be used to demonstrate an important point about control system performance (for example, the performance of mechanical collectors at low boiler load) were included in this section. Also, where no complete emission test data was available, such as for ESPs on industrial oil-fired boilers, data from other studies are presented and used to characterize control system performance.

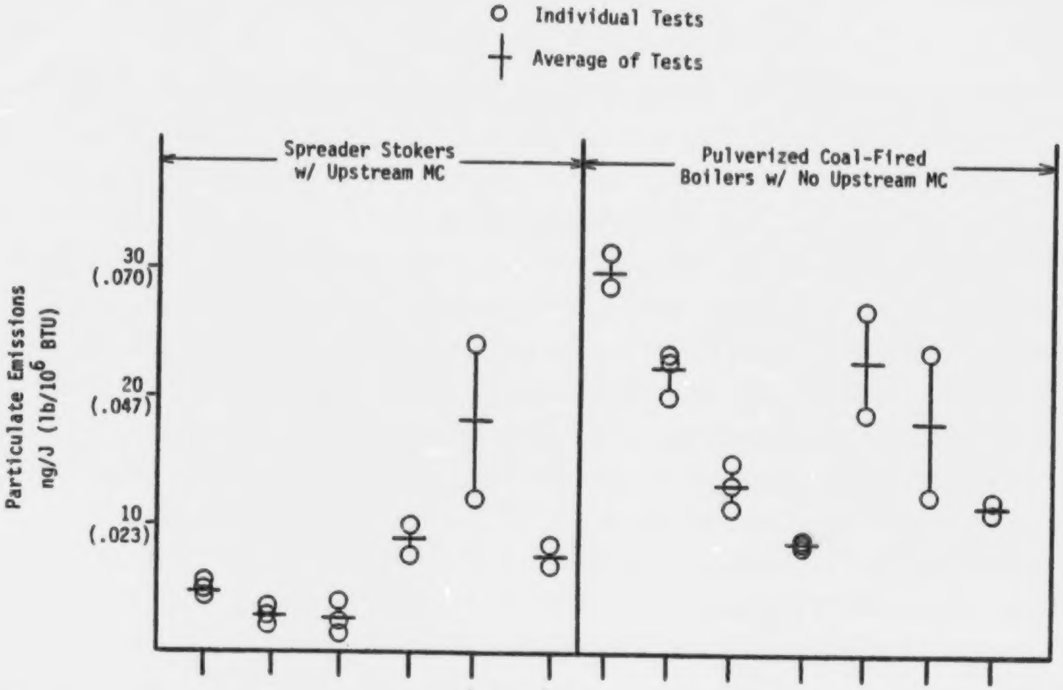
Appendix C provides further information for the majority of the data presented in this section. Appendix C also includes data that was collected with valid test methods but was considered not to be representative of well designed and operated systems. Specific documentation of why these tests were not considered to be representative is specified in Appendix C. Following such a procedure allows this section to focus primarily on emission data that represents the PM control levels achievable with well designed, operated, and maintained systems.

Method 5 tests are normally run at a sample box temperature of about 120°C (248°F). Method 5 specifications state that tests can be run at higher temperatures as specified in individual emission standards [Subpart D for fossil fuel fired industrial boilers larger than 73.3 MW (250×10^6 Btu/hr) allows temperatures up to 160°C (320°F)]. In many cases, variations in sample box temperature across this range have little or no effect on the amount of PM matter emissions measured. However, it appears that in measuring particulate matter emissions from boilers firing high sulfur coal, low sample box temperatures can lead to condensation of gaseous SO_3. This condensation may result in a difference in measured emissions, depending on coal sulfur content and sample box temperatures. Some of the emission data in this section were taken at higher sample box temperatures of [up to 177°C (350°F)] in an attempt to prevent SO_3 interference. Data collected at the high sample box temperature is referred to as high temperature Method 5 data. High temperature data is presented and discussed where available.

This section concludes with a discussion of the available data on the performance of post-combustion PM controls with respect to fine particulate (Section 4.1.6.6) and data on visible emission (Section 4.1.6.7).

4.1.6.1 ESP Emission Data. This section presents data from emission tests performed on oil- and coal-fired boilers equipped with ESPs. The only data available for ESPs on oil-fired units were gathered in a study of utility boilers, but the technology is directly transferable to industrial oil-fired boilers.

Particulate emission data from coal-fired industrial boilers equipped with ESPs are shown in Figure 4.1-20. Method 5 data were collected for both spreader stokers and pulverized coal-fired units. Specific collection area (SCA) is the most important control system design and operating parameter for ESPs. Figure 4.1-20 lists both the design and operating SCA, as well as



Plant	K	K	K	P	N[b]	N[b]	Z	Z	Z	Z	W	W	W
Boiler Number	9	7	8	-	-	-	26	27	25	29	RC	BB	PG
Design Capacity (10^3 lb steam/hr)	125	75	100	200	300	300	430	430	430	430	380	300	300
Operating Capacity (% of Design)	99-102	103-106	93-98	87-89	76	52-59	95-98	96-97	99-100	99-100	72-85	86	91
SCA ($ft^2/10^3$ acfm)													
Design	128	132	152	349	344	344	90	96	98	98	300	369	325
Operating	128	128	160	397	542	634	90	96	98	98	348	348	364
Fuel Type[c]	B	B	B	B	SB	SB	B	B	B	B	-	-	-
Fuel Sulfur (Wt %)	.57	-	~1	.73	.54	.63	~1	~1	~1	~1	-	-	-
Fuel Ash (Wt %)	11.4	12.0	11.2	6.6	8.3	5.4	~12	~12	~12	~12	-	-	-
Fly Ash Reinjection	No	No	No	Yes	Yes	Yes	No	No	No	No	No	No	No

Figure 4.1-20. Electrostatic precipitator emission data.[a]

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[a] All tests ordered from left to right by increasing SCA

[b] All tests done on a hot side ESP

[c] B-Bituminous coal, SB-Sub Bituminous coal

coal sulfur content, boiler load during the test, and whether or not there was fly ash reinjection during the emission test.

All but one of the tests were conducted on boilers with the ESP located downstream of the air preheater (cold-side ESP). At Plant N, however, the ESP is located upstream of the air preheater (hot-side ESP).

All of the emission tests shown in Figure 4.1-20 were conducted on boilers firing low sulfur coals (1 percent sulfur or less). As discussed earlier in Section 4.1.1, a larger collection area is generally required to achieve a given particulate collection efficiency on low sulfur coal units than on high sulfur coal units. Thus, the achievable emission control levels shown in Figure 4.1-20 would be achievable on boilers firing high sulfur coal with SCAs equal to or less than those shown.

Average emissions were less than 20 ng/J (0.047 lb/million Btu) in each of the six tests of spreader stoker boilers equipped with ESPs. Each of the spreader stokers tested had mechanical collectors operating upstream of the precipitator. Operating specific collection areas of the cold side ESPs on spreader stokers ranged from 419 to 1302 $m^2/(10^3m^3/s)$ (128 to 397 $ft^2/10^3$ acfm). The hot side ESP at Plant N operated with SCAs of 1774 to 2075 $m^2/(10^3m^3/s)$ (542 to 634 $ft^2/10^3$ acfm).

Six of seven tests on pulverized coal-fired boilers equipped with ESPs averaged 23 ng/J (0.053 lb/million Btu) or less. A seventh test averaged 30 ng/J (0.070 lb/million Btu). Operating SCA's ranged from 295 to 1199 $m^2/10^3m^3/s)$ (90 to 364 $ft^2/10^3$ acfm). The highest average emissions were observed from the ESP with the lowest SCA: Boiler 26 at Plant Z has an SCA of only 295 $m^2/(10^3m^3/s)$ (90 $ft^2/10^3$ acfm).

In summary, average emissions were 30 ng/J (0.07 lb/million Btu) or less in all 13 tests. These emission levels were achieved despite relatively low SCAs in four of the tests and despite the fact that the boilers tested were burning low sulfur coal (1 percent or less).

The available emission data for oil-fired boilers equipped with ESPs are considerably less well characterized with respect to SCA and boiler load during the tests. Table 4.1-2 presents the emissions data, boiler size, and fuel characteristics for seven utility boilers equipped with ESPs.

TABLE 4.1-2. SUMMARY OF PARTICULATE EMISSION TEST DATA FOR ESPs ON OIL-FIRED BOILERS[48]

Company	Boiler Capacity (MWe)	Controlled Particulate Emissions ng/J (lb/10^6 Btu)	Control Efficiency (%)	Fuel % Sulfur	Fuel % Ash	Test Sponsor
Polaroid Corp. New Bedford	10	23.7 (0.055)	40	0.7	-	Industry
	10	30.1 (0.070)	51	0.7	-	
Boston Edison Mystic Station[b]	48	48.6 (0.113)	38	2.4[d]	-	Industry
	48	64.5 (0.150)	57	2.4	-	
	48	12.9 (0.033)	71	2.4[d]	-	
	48	66.2 (0.154)	-	2.3[d]	-	
	48	66.2 (0.154)	-	2.3	-	
Boston Edison Mystic Station	593	28.0 (0.065)	83[f]	2.2	-	EPA
		17.6 (0.041)[e]	-	2.2	-	
	595	43.9 (0.102)	69[f]	2.2	-	
		21.1 (0.049)[e]	-	2.2	-	
	589	30.1 (0.070)	78[f]	2.2	-	
		19.4 (0.045)[e]	-	2.2	-	
Hartford Electric Light Co. Middletown Station	119	30.1 (0.070)	-	1.95[d]	0.09	Industry
	117	24.5 (0.057)	-	1.86[d]	0.07	
	119	28.8 (0.067)	-	1.79[d]	0.07	
United Illuminating Co. Bridgeport Harbor[b,c]	406	64.5 (0.150)	-	1.80[d]	0.08	Industry
	405	54.2 (0.126)	-	1.77[d]	0.09	
Consolidated Edison Ravenswood[a]	600	7.2 (0.017)	16	0.3	0.02	Industry
Astoria[a]	320	3.5 (0.008)	51	0.3	-	Industry
	350	5.2 (0.012)	54	0.37	-	
	355	5.2 (0.012)	40	0.3	-	
	385	5.2 (0.012)	45	0.37	-	

[a] ESP originally designed for coal.

[b] ESP originally designed for coal, later modified for oil.

[c] SCA = 375 $ft^2/10^3$ acfm (design).

[d] Oil additives used to prevent boiler fouling and corrosion.

[e] Based on EPA Method 5 high temperature method (320°F).

[f] Efficiency calculation based on low temperature Method 5 inlet and outlet data

Most of the test data presented were performed by industry, however, as noted in the table one series of tests were performed by EPA for the purpose of this study. Most of the precipitators were designed to collect coal fly ash. Generally, the collection efficiency of the ESP is lower when it is used to control fly ash from oil combustion than when it is used to collect coal fly ash. The lower collection efficiency is due primarily to differences in particle resistivity, size distribution, and surface properties between oil and coal fly ash. Thus, larger ESP collection areas may be required to achieve a given level of control when the boiler is switched from coal to oil.

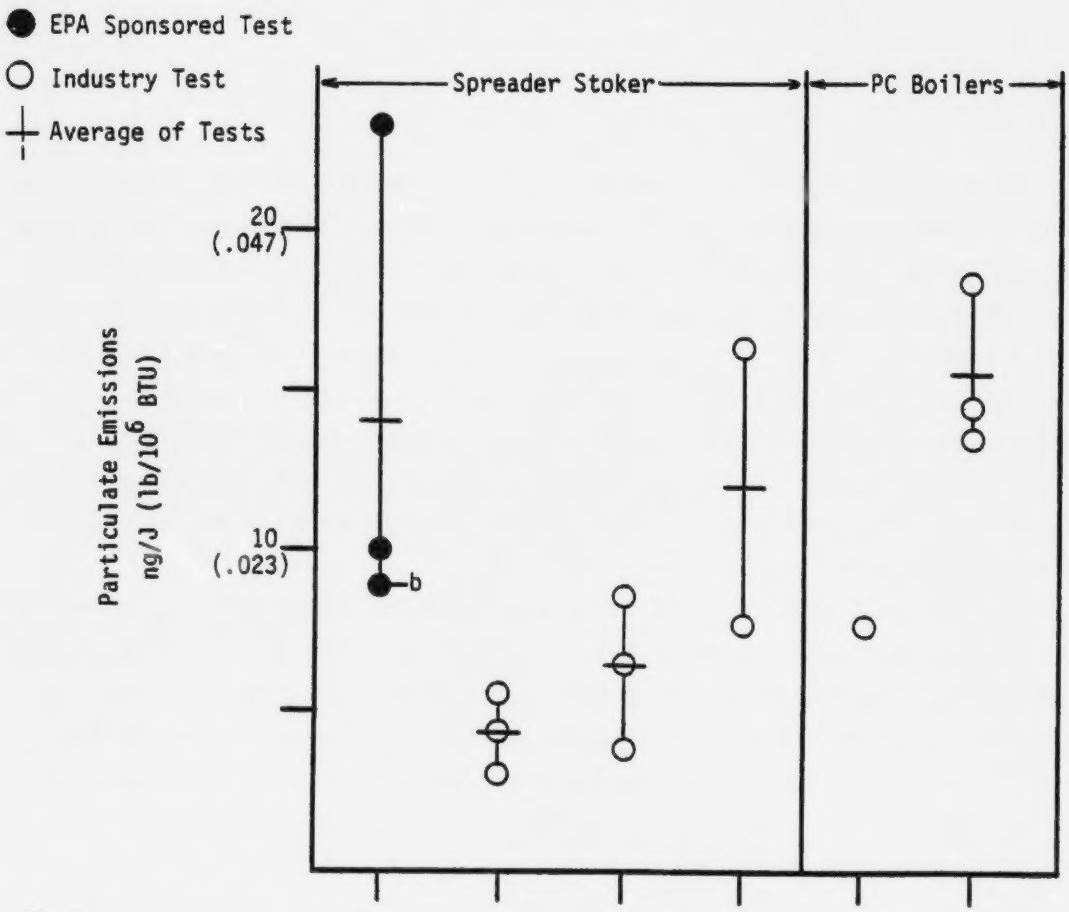
The Method 5 data in Table 4.1-2 shows controlled emissions ranging from 3.5 to 66.2 ng/J (0.008 to 0.154 lb/10^6 Btu). The high temperature Method 5 data collected at Boston Edison indicates that ESPs can achieve emission levels of below 22 ng/J (0.05 lb/10^6Btu). The boiler was firing a high sulfur oil (about 2.3 percent) and the ESP was originally designed to collect fly ash generated from oil combustion. Average emissions for the three EPA test runs at Boston Edison was 20 ng/J (.045 lb/10^6Btu).

4.1.6.2 Fabric Filter (FF) Emission Data. Data presented in this section are for coal-fired boilers equipped with fabric filters. No data were available for FF applications to oil-fired boilers.

Figure 4.1-21 shows emission test data for both spreader stoker and pulverized coal-fired boilers. Included in Figure 4.1-21 are boiler load, design and operating air-to-cloth (A/C) ratios, and percent ash in the fuel. All tests were conducted on reverse-air cleaned fabric filters.

Average controlled emissions were less than 15 ng/J (0.035 lb/10^6 Btu) in all four tests on spreader stoker boilers equipped with fabric filters. Air-to-cloth ratios of the fabric filters tested ranged from 2.3 to 3.5 ft/min. Two tests on pulverized coal-fired boilers showed controlled PM emissions of less than 16 ng/J (0.037 lb/10^6 Btu) with operating A/C ratios of 1.5 and 2.2 ft/min.

4.1.6.3 Wet Scrubber Emission Data. Particulate emission test data for spreader stoker and pulverized coal-fired industrial boilers equipped



Plant	J2	EE	EE	EE	KK	C
Boiler Number	4	4	2	5	-	-
Design Capacity (10^3 lb steam/hr) (10^6 Btu/hr)	 55 -	 100 125	 50 64	 150 181	 260 -	 250 -
Operating Capacity (% of Design)	84-96	77-78	98-100	96	83	100
Air/Cloth acfm/ft^2						
Design	2.5	3.7	3.4	3.7	1.9	2.3
Operating	2.3	2.9	3.4	3.6	1.7	2.2
Fuel Sulfur (Wt %)	0.83	2.6	2.7	2.95	0.73	0.52
Fuel Ash (Wt %)	6.9	7.0	7.0	6.5	15.0	10.2

Figure 4.1-21. Fabric filter emission data.[a]

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[a] All tests ordered from left to right by increasing air-to-cloth ratio

[b] This test includes a soot blowing cycle

with wet scrubbers are presented in Figure 4.1-22. All of the data are for wet scrubbers designed for combined SO_2 and PM removal.

As discussed in Section 4.1.3, venturi and tray scrubbers are the most suitable type of scrubbers for PM removal; test data were available for both types of scrubbers. Higher gas-side pressure drop across the scrubber generally results in lower controlled emissions.

Emission test data for wet scrubbers applied to pulverized coal-fired industrial boilers are shown in the right sections of Figure 4.1-22. Average controlled emissions in all 4 tests were less than 35 ng/J (0.081 lb/10^6 Btu).

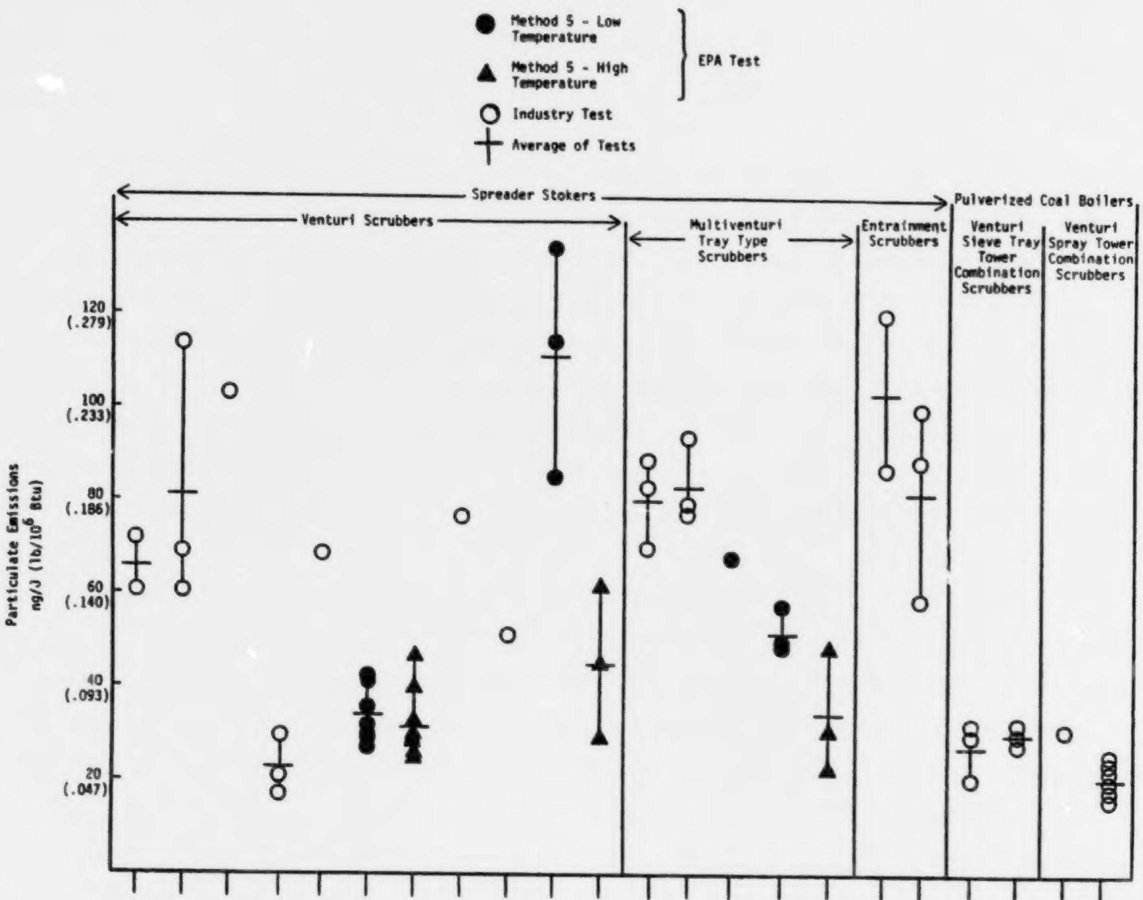
Emission test data for wet scrubbers applied to coal-fired spreader stokers are shown in the left three sections of Figure 4.1-22. High temperature Method 5 data are available for venturi scrubbers and tray-type scrubbers. Average high temperature controlled emissions from the tray-type scrubber tested (Plant AAA) is below 35 ng/J (0.08 lb/10^6 Btu) while average high temperature controlled emissions from the venturi scrubber (Plant LL) range from 45 ng/J (0.10 lb/10^6 Btu) to 38 ng/J (0.08 lb/10^6 Btu) for two similar boiler scrubber combinations. Both plants have upstream mechanical collectors as particulate precleaners prior to final particulate removal in the SO_2 scrubbers.

Average controlled emissions from two entrainment type scrubbers (Plant O) were 82 and 104 ng/J (0.191 and 0.241 lb/10^6 Btu), at operating scrubber pressure drops of 3 kPa (12 in. w.g.).

Limited test data is also available for wet scrubber systems applied to utility coal-fired boilers. This data is presented in Table 4.1-3. The scrubber systems tested are all designed for SO_2 as well as PM removal.

4.1.6.4 Mechanical Collector Emission Data. Particulate emission data for coal-fired boilers equipped with single and dual mechanical collectors are presented in this section.

Figure 4.1-23 shows Method 5 data for single and dual mechanical collectors installed on five spreader stokers, while Figure 4.1-24 shows data for single mechanical collectors installed on three mass fed stokers. Dual mechanical data were available only for one spreader stoker under



Plant	QQ	QQ	QQ	L	MM	LL	LL	MM	LL	LL	LL	M	M	SS	AAA	AAA	O	O	OO	OO	TT	TT
Boiler No.	4	5	5	3	2	20	20	3	19	19	19	1	4	3	1	1	3	2	-	-	-	-
Design Capacity (10^3 lb steam/hr) (10^6 Btu/hr)	- 202	- 202	- 202	100 -	- 295	- 236	- 236	- 295	- 236	- 236	- 236	100 -	60 -	60 -	100 -	100 -	100 -	80 -	- 137	- 137	- 100	- 100
Operating Capacity (% of Design)	80-100	80-95	95	93-97	75	85-91	85-91	75	100	73	73	86-92	79-83	81	92	92	80-100	88	100	100	100	100
Emission Controls[b]	5	5	5	2	7	7	7	7	7	7	7	3	3	3	3	3	4	4	6	6	1	1
Scrubber Pressure Drop (in H_2O guage)																						
Design	22	22	22	10	17	17	17	17	17	17	17	13	13	13	13	13	12	12	-	-	-	-
Operating	8	8	8	10	16	17.3	17.3	17.5	18.1	19.3	19.3	7.5	7.5	7.5	7.5	7.5	12	12	12/45[c]	17/45[c]	3[d]	9[d]
Design L/G (gpm/10^3 acfm)	11.4	11.4	11.4	-	10	10	10	10	10	10	10	20	20	-	-	-	-	-	20	20	4	17
Fuel Sulfur (wt %)	2.4-3.4	2.4-3.4	2.4-3.4	0.8	2.4-3.4	2.54	2.54	2.4-3.4	2.4-3.4	2.6	2.6	2.3	2.4	2.14	1.33	1.33	2.33	2.33	3.5	3.5	3.9	3.9
Fuel Ash (wt %)	10	10	10	7.2	10	10.4	10.4	10	10	11.4	11.4	9.4	8.0	5	4.4	4.4	10.5	9.9	12.3	12.3	14.7	14.7
Fly Ash Reinjection	Yes	Yes	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No

Figure 4.1-22. Emission data for wet scrubbers.[a]

Notes for Figure 4.1-22.

[a] Venturi tests ordered by increasing operating pressure drop.

All other tests ordered by decreasing percent ash in fuel.

[b] PM and SO control devices

1. Ventur/spray tower
2. 95 percent efficient mechanical collector, FMC venturi dual alkali scrubber.
3. Mechanical collector, multi-venturi flex tray dual alkali scrubber.
4. Mechanical collector, Zurn entrainment type scrubber.
5. 80 percent efficient mechanical collector, venturi dual alkali scrubber.
6. Venturi/seive tray scrubber.
7. Mechanical collector, venturi dual alkali scrubber with cyclonic separators.

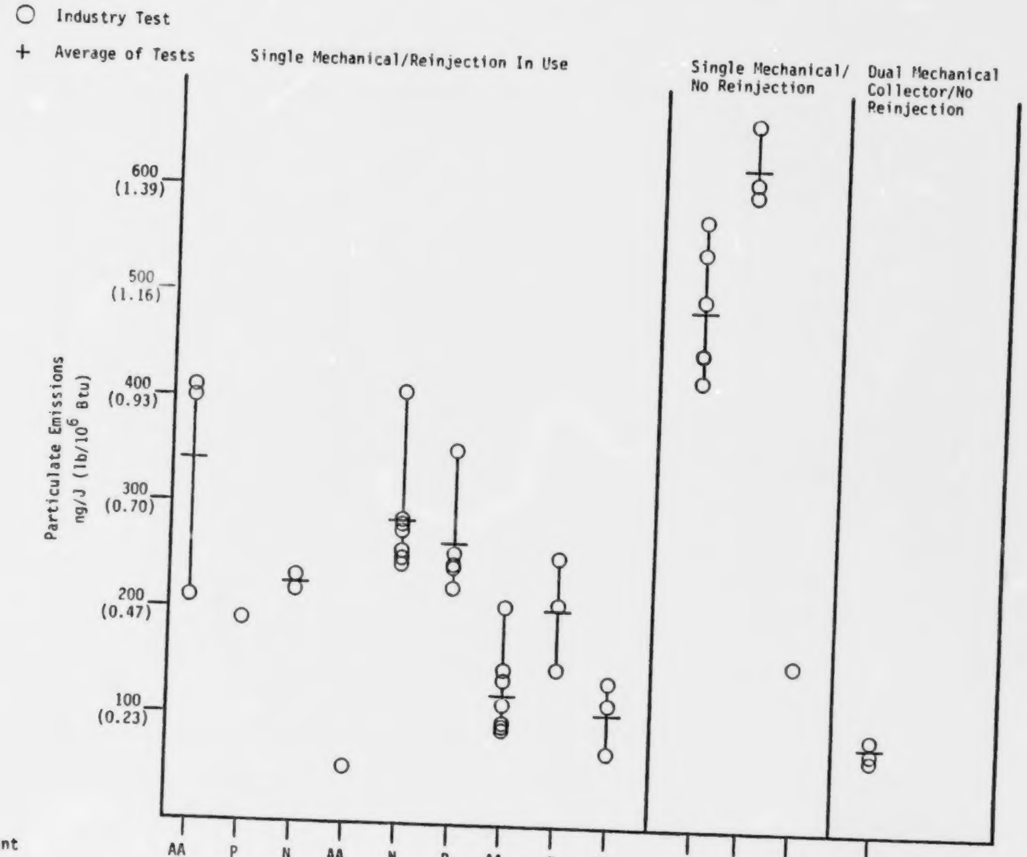
[c] Venturi Δp/ sieve tray Δp.

[d] Δp for venturi only.

TABLE 4.1-3. DATA ON PARTICULATE SCRUBBING SYSTEMS INSTALLED ON COAL-FIRED UTILITY STEAM GENERATORS 48

Boiler Type[a] and Size[b] (% Sulfur)	Particulate Control Before Scrubbing	Separate Particulate Control by Scrubbing	SO_2 or SO_2 and Particulate Control By Scrubbing	System Pressure Drop Kilopascals (Inches H_2O)	Particulate Emissions at the Scrubber Outlet ng/J (lb/10^6 BTU)	Number of Tests	Test Method
125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	20-24 (0.046-0.055)	2	EPA 5
125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	22 (0.051)	2	EPA 5
125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	14-18 (0.033-0.041)	3	EPA 5
350MW-PC (0.7)	None	None	Venturi Scrubber Lime	4.5 (18)	8-10 (0.019-0.023)	3	EPA 5
116MW-PC (0.5)	Mechanical	Flooded Disc Scrubber	Packed Absorber Lime	3.0 (12)	16 (0.037-0.038)	2	EPA 5
380MW-PC (2.1)	Mechanical and ESP	None	Venturi	2.5 (10)	19-21 (0.045-0.048)	2	EPA 5
150MW-PC (2.1)	Mechanical	None	Venturi	2.5 (10)	9-30 (0.022-0.070)	10	EPA 5

[a] PC = Pulverized Coal
[b] MW = MW_e Output



Plant	AA	P	N	AA	N	P	AA	P	AA	UU	UU	AA	PP
Boiler No.	G	–	–	G	–	–	G	–	G	–	–	G	–
Boiler Type[b]	SP	SP	SP	SP	SP	SP	SP	SP	SP	SP	SP	SP	SP
Design Capacity (10^3 lb steam/hr)	75	200	300	75	300	200	75	200	75	160	160	75	145
Operating Capacity (% of Design)	16-17	47	37-59	57	60-74	73-79	76-86	81-100	97-102	55-60	59-60	98	~100
Fuel Sulfur (Wt %)	0.92	0.84	0.77	0.75	0.91	0.92	0.72	0.90	0.90	0.8	0.8	0.75	0.74
Fuel Ash (Wt %)	7.3	8.9	7.2	8.3	5.3	7.4	7.5	8.0	6.8	10.3	10.3	8.3	6.4

Figure 4.1-23. Single and dual mechanical collector emission data for spreader stokers.

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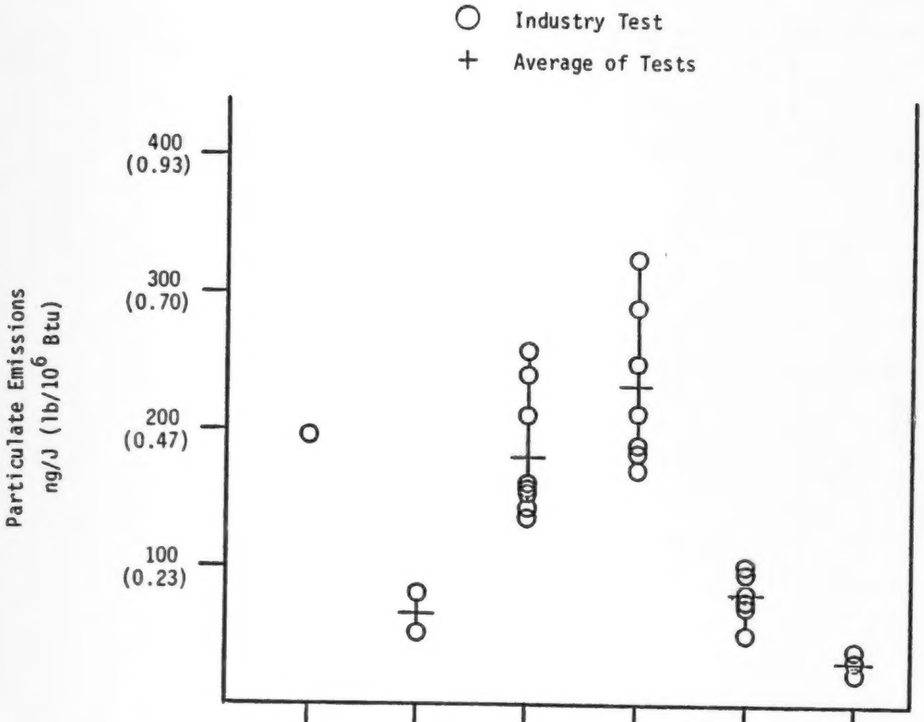
[a] All tests ordered from left to right by increasing operating capacity

[b] SP-spreader stoker



Plant	R	HH	R	R	HH	H
Boiler No.	-	-	-	-	-	-
Boiler Type[b]	VG	CG	VG	VG	CG	U
Design Capacity (10^3 lb steam/hr)	90	70	90	90	70	35
Operating Capacity (% of Design)	45	48-50	61-69	79-89	73-103	77-90
Fuel Sulfur (Wt %)	2.23	1.82	2.26	1.89	1.65	0.57
Fuel Ash (Wt %)	8.2	9.0	8.1	7.2	7.0	8.1

Figure 4.1-24. Mechanical collector emission data for mass fed stokers without fly ash reinjection.[a]

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[a] All tests ordered from left to right by increasing operating capacity.

[b] VG-vibrating grate stoker, CG-chain grate stoker, U-underfeed.

relatively steady steam demand conditions. Although dual mechanical collector data is limited, the available data falls within the range of performance for single stage mechanical collectors.

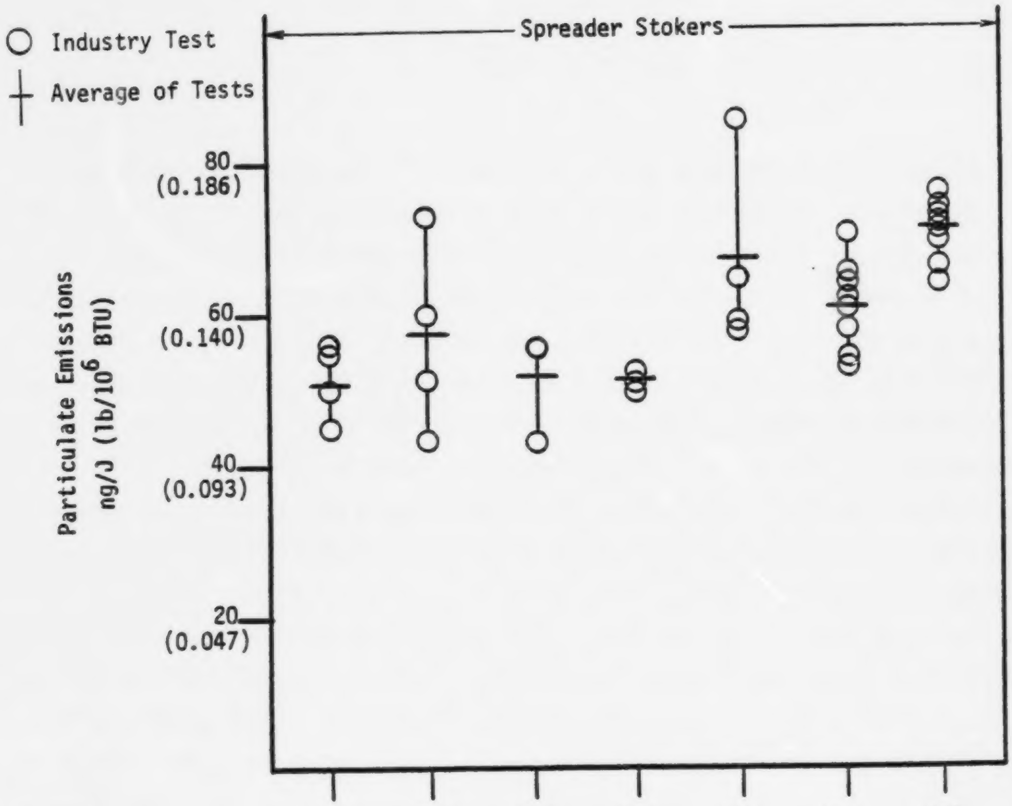
Figures 4.1-23 and 4.1-24 suggests that mechanical collector performance is extremely variable from plant to plant. This may be a result of different boiler loads, cyclone tube diameters, coal types and operation and maintenance procedures. Because of this variability, an estimation of mechanical collector performance from this data is difficult. Figure 4.1-23 shows that average outlet emissions from mechanical collectors applied to spreader stokers cover a wide range from 50 ng/J (0.12 $lb/10^6$ Btu) to 617 ng/J (1.43 $lb/10^6$ Btu).

Average controlled emissions in 10 of 12 tests on spreader stokers equipped with single mechanical collectors were 340 ng/J (0.79 $lb/10^6$ Btu) or less. The highest average emissions of these 10 tests occurred at low boiler load (16 to 17 percent). Two other tests on a spreader stoker equipped with single mechanical collector averaged more than 430 ng/J (1.0 $lb/10^6$ Btu).

Particulate emission data for single mechanical collectors applied to chaingrate, vibrating grate and underfeed stokers is presented in Figure 4.1-24. Average emissions from the vibrating grate stoker range from 180 to 230 ng/J (0.42 to 0.53 $lb/10^6$ Btu) while the limited underfeed stoker data averages 31 ng/J (0.07 $lb/10^6$ Btu). Average particulate emissions from the chaingrate stoker tested range from 65 to 79 ng/J (0.15 to 0.18 $lb/10^6$ Btu).

Only one test was available for mechanical collectors on oil-fired boilers. Two Method 5 tests were performed at Plant ZZ on a 55,000 lb steam/hr boiler firing No. 2 oil. The boiler was operated at 67 percent of capacity during the tests. The results show an average emission of 9 ng/J (0.02 $lb/10^6$ Btu). Fuel oil sulfur content in this test was less than 1 percent, and ash content of the oil was reported as "nil".

4.1.6.5 Side Stream Separator Emission Data. Particulate emissions from spreader stoker boilers equipped with side stream separators are presented in this section and Figure 4.1-25. No EPA tests were performed,



Plant	DDD	CCC	GGG	EEE	FFF	EEE	BBB
Boiler Number	-	-	-	1	3	3	3
Design Capacity (10^3 lb steam/hr)	45	70	60	40	100	55	52
Operating Capacity (% of Design)	68[b]	71-80	74-80	84-93	85-97	99-105	97-108
Average Opacity (%)	0[c]	-	-	6.9	0	0[c]	6[c]
Fuel Sulfur (Wt %)	0.82	0.80	0.94	1.79	1.67	2.09	0.80
Fuel Ash (Wt %)	9.7	10.1	4.3	9.0	6.1	8.8	7.8
% of Flow to Baghouse	16[b]	31	30	37	15	15	17

Figure 4.1-25. Side stream separator emission data.[a]

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[a] All tests ordered from left to right by increasing operating capacity

[b] Data presented are averages for all tests

but industry has provided test results from seven stoker boilers using retrofitted side stream separators. The side stream separator has not been applied to pulverized coal-fired boilers or mass fed stokers.

The results show that under relatively steady state conditions, average emissions from newly installed and adjusted collectors were less than 72 ng/J (0.17 lb/10^6Btu) at all seven locations. Average emissions during the tests ranged from 52 ng/J (0.12 lb/10^6Btu) to 72 ng/J (0.17 lb/10^6Btu). All emissions tests were performed using Method 5. The boilers tested operated under relatively steady state conditions and at boiler loads at or above 68 percent. No data was collected for low load or variable load operations. Percent ash in the fuel varied from site to site and ranged from 4.3 to 10.1 percent. The percent of the total flow sent to the baghouse also varied from site to site and ranged from 15 to 37 percent. It should be noted that extensive adjustment of the existing mechanical collectors was required to achieve the emission levels shown in Figure 4.1-25.[53]

4.1.6.6 Fine Particulate Collection Efficiency. In addition to the overall collection ability of post-combustion PM control devices, another important factor characterizing their performance is the ability to collect fine and inhalable particulate matter. In general, inhalable particulate matter is defined as that particulate matter having an aerodynamic diameter of 15 microns or less, while fine particulate matter is defined as that having of aerodynamic diameter of 2.5 microns or less. (These definitions are used for discussion purposes only.)

This section presents the available data for the fine particulate control capability of ESPs, fabric filters, wet scrubbers and dual mechanical collectors. The limited data available for single mechanical collectors were obtained with two different particle size methods and the results were generally inconsistent. Therefore, data for single mechanical collectors are not presented here; the ability of mechanical collectors to capture fine particulate was discussed qualitatively in Section 4.1.4. No data on the fine particulate collection efficiency of side stream separators (SSS) were available. However, particle size testing on this device has indicated that the slipstream to the fabric filter has a high percentage of particles less than 10 microns, and other data shows fabric filters to have high collection efficiencies on small particles.[50] Thus, the SSS should have higher fine particulate collection efficiencies than a mechanical collector.

The data presented in this section indicate that high efficiency ESPs and fabric filters show the greatest degree of control of fine particulate. Venturi scrubbers offer limited control of fine particulate from spreader stokers, but are fairly effective in controlling fine particulate from PC's.

Table 4.1-4 shows the available data for ESPs, fabric filters and wet scrubbers. Also shown in Table 4.1-4 is the boiler type, fuel, and available control device design or operating parameters. Data were available for industrial spreader stoker and residual oil-fired boilers and for utility pulverized coal-fired units.

Two ESPs, both operating on low sulfur pulverized coal-fired utility boilers, showed 97.4 and 98.5 percent removal of fine particulate, respectively. [Specific collection areas were 79 and 96 $m^2/m^3/s$, respectively]. Three tests were performed on a utility size spreader stoker equipped with a reverse air fabric filter system. Fine particulate removal efficiency was 99.8 percent and above for all three tests. These data include the effect on outlet emissions from the reverse air/mechanical shaker bag cleaning system.

Fine particulate collection efficiencies of venturi scrubbers on utility pulverized coal-fired boilers ranged from 51.8 to 91.8 percent; two of the three units were operated at 2.3 to 2.5 kPa (9 and 10 in. H_2O) pressure drop. Data from one spreader stoker equipped with a venturi scrubber, operating at 3 kPa (12 in. H_2O) pressure drop, showed 35.3 percent efficiency on fine particulate. Venturi scrubbers on two boilers firing residual oil showed fine particulate collection efficiencies of 44.7 and 49.5 percent.

An EPA-tested dual mechanical collector, operating on a high sulfur coal-fired spreader stoker, collected virtually no fine particulate, (<2.5 microns) but did collect 23.9 percent of the inhalable particulate

TABLE 4.1-4. FINE PARTICULATE CONTROL EFFICIENCY FOR VARIOUS PM CONTROL DEVICES[a]

Control Device	Boiler Type[c]	Fuel[c]	Fractional Collection Efficiency % of Particles ≤2.5	Control Device Parameters
ESP	Utility - PC	LSC	97.4	SCA = 79 $m^2/m^3/s$ ($ft^2/10^3$ acfm)
Fabric Filter	Utility - PC	LSW	99.4	--
Fabric Filter	Utility - PC	ANTH	99.9	Teflon coated glass fabric; reverse-air cleaned
Fabric Filter	Utility - SP	LSC	99.9	Silicone coated glass; A/C = 1.9:1
"	"	"	99.9	" ; A/C = 2.5:1
"	"	"	99.8	" ; A/C = 2.8:1
Venturi Scrubber	Utility PC	LSE	91.8	--
Venturi Scrubber	Utility PC	Coal[d]	79.3	Δp = kPa (9 in. H_2O)
Venturi Scrubber	Utility PC	Coal[d]	51.8	Δp = kPa (10 in. H_2O)
Venturi Scrubber	Spreader Stoker	HSE	35.3	Δp = kPa (12 in. H_2O)
Venturi Scrubber	Industrial	Residual Oil	49.5	--
Venturi Scrubber	Industrial	Residual Oil	44.7	--

[a] Source: Sedman, Charles B. Memo and attachments to Industrial Boiler files. Performance of Emission Control Systems on Fine Particulates. April 21, 1981. (Reference 231).

[b] Fine particulate defined as that particulate matter with an aerodynamic diameter of 2.5 microns or less.

[c] PC = pulverized coal-fired.
LSC = low sulfur coal; LSW = low sulfur western coal.
ANTH = anthracite; LSE = low sulfur eastern coal
HSE = high sulfur eastern coal.
SP = spreader stoker

[d] Coal sulfur not specified.

matter (<15 microns). As discussed earlier, these tests may not be fully representative of system performance due to air leakage, therefore, the tests are not included in Table 4.1-4.

4.1.6.7 Visible Emissions. This section presents the available visible emission data for ESPs, fabric filters, wet scrubbers, mechanical collectors and side stream separators. Table 4.1-5 lists data obtained using continuous transmissometers. Table 4.1-6 lists data obtained using the EPA Method 9. Tests in which soot blowing occurred are noted in Table 4.1-6.

The opacity of flue gas exiting the stack of industrial boilers utilizing fabric filters, ESPs, and wet scrubbers for particulate emission control was less than 10 percent for all data presented. Opacity data from spreader stokers equipped with side stream separators showed opacities ranging from 0 to 10 percent. The opacity of the stack gas from industrial boilers utilizing mechanical collectors for particulate emission control ranged from 5 to 35 percent depending to a large degree on the PM emission level. The lower opacities were observed from a small underfeed stoker; underfeed stokers generally have much lower uncontrolled emission rates than spreader stokers.

Opacity evaluations in Table 4.1-6 indicate that, when soot blowing is continuous or scheduled on a frequent and regular basis, soot blowing has little effect on opacity. Additional data indicate that, during soot blowing, opacity was not increased more than 0 to 4 percent.[55]

4.2 POST-COMBUSTION TECHNIQUES FOR SO_2 CONTROL

Post-combustion techniques for controlling SO_2 emissions from industrial boilers are discussed in this section. The flue gas desulfurization (FGD) processes discussed are:

- Sodium Scrubbing
- Dual Alkali
- Lime and Limestone (with and without adipic acid addition)
- Dry Scrubbing

Each of these FGD systems is currently being used commercially to remove SO_2 from industrial boiler flue gases with the exception of adipic acid enhanced

TABLE 4.1-5. OPACITY TRANSMISSOMETER DATA

Type of Boiler	Boiler Load 10^3 lb/hr[a]	Control Equipment	Particulate Mass Loading ng/J	Particulate Mass Loading lb/10^6 Btu	Opacity Percent
Pulverized Coal (Plant KK)	168	Fabric Filter	12.8	0.030	0
	166		8.4	0.020	0
	164		7.8	0.018	0
	215		7.8	0.018	0
	173		6.4	0.015	0
	189		4.3	0.010	0
	167		2.5	0.006	0
	185		3.2	0.007	0
	170		3.2	0.008	0
Spreader Stoker (Plant UU)	94	Mechanical Collector	670	1.55	35
	96		610	1.42	35
	95		600	1.40	25
	94		570	1.34	30
	94		540	1.26	25
	88		500	1.16	25
	95		450	1.05	25
	93		450	1.05	25
	95		420	0.99	25
Spreader Stoker (Plant VV)	70	Mechanical Collector	400	0.931	10
	70		360	0.839	10
	72		360	0.842	10
	71		350	0.827	10
	56		300	0.690	10
	61		260	0.596	12
	60		250	0.577	11
	70		240	0.553	10
	69		220	0.516	10
	49		220	0.513	10
	52		180	0.426	10
	16		160	0.380	11
Spreader Stoker (Plant EE #2)	50	Mechanical Collector and Fabric Filter	3.9	0.009	<10
	49		6.5	0.015	<10
	49		8.6	0.020	<10
Spreader Stoker (Plant EE #4)	77	Mechanical Collector and Fabric Filter	3.0	0.007	<10
	78		4.3	0.010	<10
	78		5.6	0.013	<10

TABLE 4.1-5. (CONTINUED)

Type of Boiler	Boiler Load 10^3 lb/hr[a]	Control Equipment	Particulate Mass Loading ng/J	Particulate Mass Loading lb/10^6 Btu	Opacity Percent
Spreader Stoker (Plant EE #5)	145	Mechanical Collector and Fabric Filter	7.7	0.018	<10
	144		16	0.038	<10
Vibrating Grate Stoker (Plant R)	78	Mechanical Collector	320	0.754	35
	78		290	0.667	19
	55		260	0.595	11
	77		250	0.574	23
	58		240	0.557	30
	80		210	0.490	29
	57		210	0.488	12
	79		180	0.424	19
	71		180	0.421	19
	78		170	0.393	32
	59		160	0.372	12
	57		150	0.354	12
	59		140	0.328	12
	58		140	0.319	12
Spreader Stoker (Plant BBB)	55	Sidestream Separator	75	0.175	6
	53		74	0.173	6
	50		74	0.171	6
	56		72	0.167	6
	55		72	0.166	6
	54		71	0.164	6
	51		66	0.154	6
	55		65	0.151	6
Spreader Stoker (Plant EEE) Boiler #1	37	Sidestream Separator	53	0.123	10
	34		52	0.120	5
	36		50	0.117	5
Spreader Stoker (Plant EEE) Boiler #3	40	Sidestream Separator	71	0.165	0
	41		66	0.153	0
	42		64	0.149	0
	42		62	0.144	0
	40		61	0.143	0
	40		59	0.136	0
	41		54	0.126	0
	40		53	0.123	0

[a] Steam output from boiler.

TABLE 4.1-6. OPACITY-EPA REFERENCE METHOD 9

Type of Boiler	Boiler Load 10^3 lb/hr[a]	Control Equipment	Particulate Mass Loading ng/J	Particulate Mass Loading lb/10^6 Btu	Opacity Percent[b]
Pulverized Coal (Plant C)	250	Fabric Filter	18	0.043	2.5[c]
	250		15	0.034	2.5
	250		14	0.032	2.5
Spreader Stoker (Plant JJ) (Pulse Jet Cleaning Mode)	80	Fabric Filter	6	0.013	0
Spreader Stoker (Plant JJ) (Reverse Air Cleaning Mode)	75	Fabric Filter	5	0.011	<1
			4	0.010	0
			4	0.009	0
Spreader Stoker (Plant J2)	45	Fabric Filter	9	0.020	0
			9	0.021	<1[c]
			10	0.023	<1
			23	0.054	<1
Pulverized Coal (Plant II)	52	Scrubber	67	0.157	<1
			47	0.109	<1[c]
			28	0.066	<1
			21	0.048	0
Residual Oil Fired (Plant HHH)	3744	ESP	44	0.102	5.7[d]
	3789		30	0.070	<1[d]
	3735		28	0.065	8[d]
Spreader Stoker (Plant K-Boiler #9)	124	ESP	5.6	0.013	2.3
	126		5.2	0.012	<1
	124		4.3	0.010	<1
Underfeed Stoker (Plant H)	31	Mechanical Collector	30	0.09	<5
	27		30	0.07	<5
	28		26	0.06	<5
Spreader Stoker (Plant XX)	75	Mechanical Collector	220	0.506	17
	75		170	0.392	17
	75		210	0.494	22
	60		110	0.253	22

TABLE 4.1-6. OPACITY-EPA REFERENCE METHOD 9 (CONTINUED)

Type of Boiler	Boiler Load 10^3 lb/hr[a]	Control Equipment	Particulate Mass Loading ng/J	Particulate Mass Loading lb/10^6 Btu	Opacity Percent[b]
Spreader Stoker (Plant FFF)	90	Sidestream Separator	70	0.156	<1
Spreader Stoker (Plant DDD)	31	Sidestream Separator	56	0.130	0
	31		55	0.128	0
	31		50	0.116	0
	31		45	0.104	0

[a] Steam output from boiler.

[b] Average of six-minute readings.

[c] Included a soot blow cycle.

[d] Soot blown continuously.

FGD. Each system relies on either a calcium- or sodium-based sorbent to react with SO_2 to form sulfite and sulfate salts, thereby removing SO_2 from the flue gas stream.

The following sections present a description of each system, and a brief evaluation of their development status, applicability, and design and operating characteristics. Continuous monitoring test data for each system is presented in Section 4.2.5.

4.2.1 Sodium Scrubbing

Sodium scrubbing processes are capable of achieving high SO_2 removal efficiencies over a wide range of inlet SO_2 concentrations. However, these processes consume a premium chemical (NaOH or Na_2CO_3) and produce an aqueous waste for disposal which contains sodium sulfite and sulfate salts.

4.2.1.1 Process Description

4.2.1.1.1 System. Sodium scrubbing processes currently being used in industrial boiler FGD applications employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. The operation of the scrubber is characterized by a low liquid-to-gas ratio [1.3 to 3.4ℓ/m^3 (10 to 25 gal/1000 ft^3)] and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. Further, the scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts. The SO_2 absorption reactions which take place in the scrubber are:[56]

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \qquad (4.2.1\text{-}1)$$

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (4.2.1\text{-}2)$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3 \qquad (4.2.1\text{-}3)$$

Simultaneously some sodium sulfite reacts with absorbed oxygen from the flue gas to produce sodium sulfate:

$$Na_2SO_3 + 1/2O_2 \rightarrow Na_2SO_4 \qquad (4.2.1\text{-}4)$$

The scrubber effluent, therefore, consists of a mixture of sodium salts.

Solids storage and handling equipment are auxiliaries associated with sodium scrubbing systems. Sodium reagent handling requirements include dry storage, usually in silos. A conveyor system is generally used to transport the reactant from the silo to a mixing tank, where the sodium alkali is dissolved to produce the scrubbing solution. The solution from the mix tank is pumped to a larger hold tank where it combines with the scrubber effluent. The majority of the hold tank liquor is recycled to the scrubber with a slip stream going to waste treatment and disposal. A simplified process flow diagram is presented in Figure 4.2-1.

4.2.1.1.2 Development status. Sodium scrubbing systems are commercialized technology; operating systems are in use on industrial boilers ranging in size from 10 to 125 MW (35 to 430 x 10^6 Btu/hr) thermal input. Table 4.2-1 presents a summary of operating sodium scrubbing systems applied to U. S. industrial boilers. Currently 102 sodium FGD systems are in operation on domestic industrial boilers, and 23 are in the planning or construction stage.[57]

4.2.1.1.3 Applicability to industrial boilers. Sodium scrubbing, because it is simple both chemically and mechanically, can be applied to boilers of varying size and type. The process has been applied to oil-fired boilers as well as stoker and pulverized coal-fired boilers.

Future applications of sodium scrubbing systems may be limited by the need to dispose of the sodium sulfite/sulfate waste liquor. As shown in Table 4.2-1 the majority of sodium scrubbing systems in use today are located in the California oil fields where the wastes are disposed of in evaporation ponds or by deep-well injection. Systems in use at industrial plant locations either reuse the waste liquor in various plant processes or dispose of it in city sewers or by mixing it with fly ash and either ponding or landfilling the waste liquor/fly ash mix. If wastes from future sodium scrubbing systems cannot be disposed of by treating them in existing waste water or ash disposal facilities, or by use as a plant process make-up

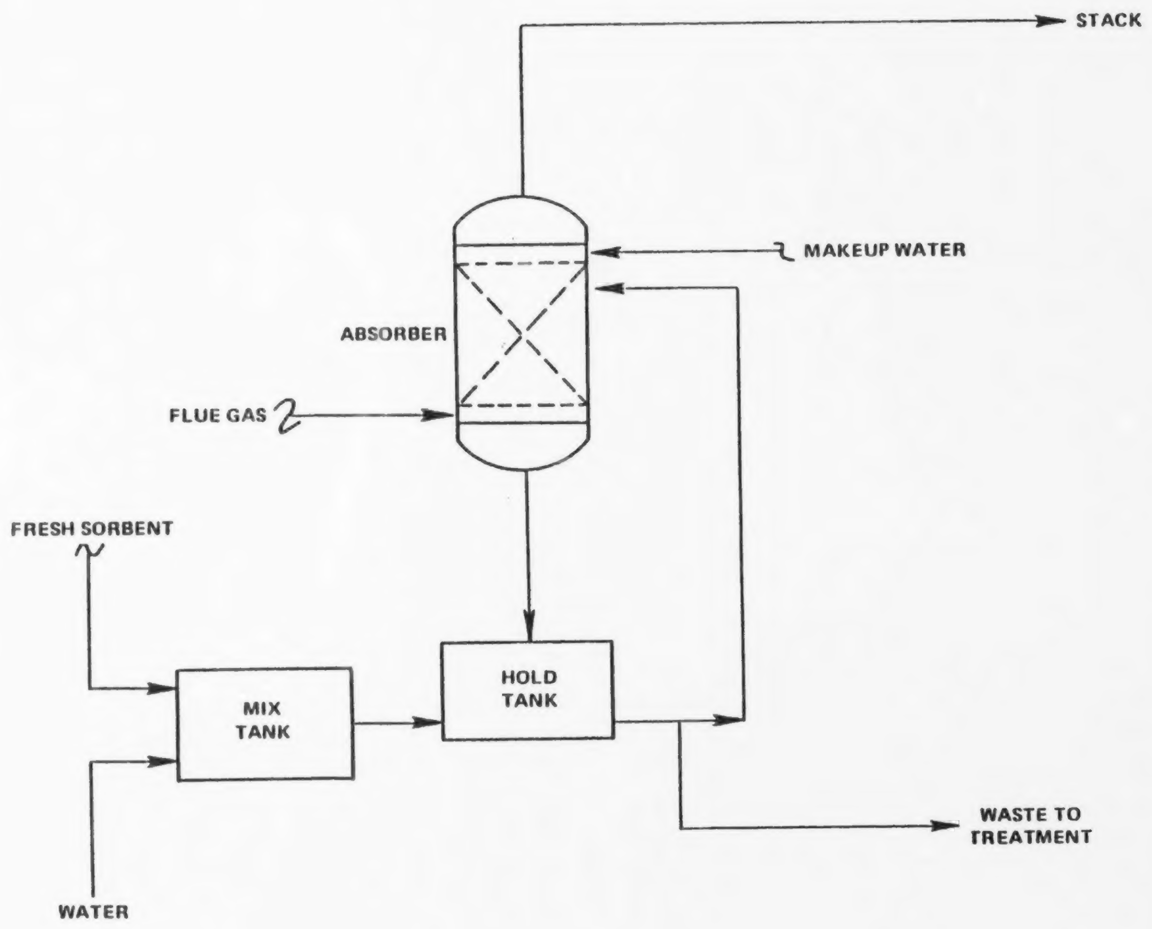
STACK
MAKEUP WATER
ABSORBER
FLUE GAS
FRESH SORBENT
HOLD TANK
MIX TANK
WATER
WASTE TO TREATMENT

Figure 4.2-1. Simplified flow diagram of a sodium scrubbing system.

TABLE 4.2-1. PERFORMANCE DATA FOR OPERATING SODIUM SCRUBBING SYSTEMS[57]

Installation/location	Sorbent	Fuel Type(1)	%S	Start-up Date	No. of FGD Units	SO_2(2) Inlet (ppm)	Percent(2) Removal	Waste Disposal
Alyeska Pipeline Valdez, Alaska	NaOH	O	<0.1	6/77	1	150	96	oxidation/dilution
American Thread Martin, NC	Caustic waste	C	1-1.5	1973	2	500	70	pond
Belridge Oil McKittrick, CA	NaOH	O	1.1	6/78	2	500	90	waste water treatment
Canton Textiles Canton, GA	Caustic waste	C	0.8	6/74	1	500	70	pond/waste treatment
Chevron Bakersfield, CA	Na_2CO_3	O	1.1	7/78	3	700	90	pond/waste treatment
FMC Green River, WY	Na_2CO_3	C	1	5/76	2	800	95	pond
General Motors Dayton, OH	NaOH	C	0.7-2.0	9/74	2	1.43#/10^6 BTU	86	clarify/adjust pH/ to sewer
General Motors Pontiac, MI	NaOH	C	0.8	4/76	2	—	—	combine with ash/ landfill
General Motors St. Louis, MO	NaOH	C	3.2	1972	2	2000	90	oxidize/neutralize/ discharge
General Motors Tonawanda, NY	NaOH	C	1.2	6/75	4	1#/10^6 BTU	90	combine with ash/ landfill
Georgia Pacific Orosett, AK	Caustic waste	B,C,O	1.5-2	7/75	1	500	80	to city sewers
Getty Oil Bakersfield, CA	Na_2CO_3	O	1.1	6/77-12/78	6	600	90-96	pond
Great Southern Cedar Springs, GA	Caustic waste	B,C,O	1-2	1975	2	1000	85-90	ash pond
ITT Rayonier Fernandina, FL	Caustic waste	B,O	2-2.5	1975	2	1200	80-85	to paper process
Kerr-McGee Trona, CA	Na_2CO_3	O	0.5-3	6/78	2	—	98	pond
Mead Paperboard Stevenson, AL	Na_2CO_3	O	1.5-3	1975	1	1500	95	to paper process
Mobil Oil San Ardo, CA	Na_2CO_3/NaOH	O	2-2.5	1974	28	1500	90	pond
Nekoosa Papers Ashdown, AK	Caustic waste	C	1-1.5	2/76	2	600	90	waste treatment
Northern Ohio Sugar Freemont, OH	NaOH	C	1	10/75	2	—	—	pond
St. Regis Paper Cantonment, FL	NaOH	B,O	<1	1973	1	—	80-90	clarification/ aeration
Texaco San Ardo, CA	NaOH	O	1.7	11/73	32	1000	73	pond/wells/softening and reuse
Texasgulf Granger, WY	Na_2CO_3	C	0.7	9/76	2	860	90	pond

(1) C=coal
O=oil
B=bark
PC=petroleum coke

(2) SO_2 Inlet (ppm) and percent SO_2 removal are as reported to PEDCo by the FGD system operator. Values reported may represent anything from single point wet chemically determined numbers to continuous monitoring results and may or may not be obtained by approved EPA methods.

stream, costs associated with achieving a zero discharge waste will more than likely limit the system's application.[58] Treatment and disposal of sodium scrubbing system wastes is further discussed in Chapter 7.

4.2.1.1.4 Availability/reliability. The three indices used in the EPA Industrial Boiler FGD Survey to reflect this aspect of system performance are availability, operability, and reliability. These indices are defined as follows:

Availability - Hours the FGD system was available (whether operated or not) divided by the hours in the period, expressed as a percentage.

Operability - Hours the FGD system was operated divided by boiler operating hours in the period, expressed as a percentage.

Reliability - Hours the FGD system was operated divided by the hours the FGD system was called upon to operate, expressed as a percentage.

Overall reliability of sodium scrubbing systems applied to industrial boilers has generally been quite high. Data reported in the EPA Industrial Boiler FGD Survey indicate that of the 22 industrial boiler installations which have operating sodium scrubbing systems, 15 reported quantitative reliability or operability indices that ranged from 89 to 100 percent with an average of 97.8 percent. Of the 15 responses, 9 reported a 100 percent reliability/operability and all but two reported reliabilities of greater than 95 percent.[59]

Of the seven installations that did not report quantitative reliability indices, two reported that the FGD system had no problems, two reported erosion/corrosion problems, one had down-time due to reconstruction, one had mechanical problems with pump packings, and one system had no reported comments.[60]

4.2.1.2 Factors Affecting Performance. For a given set of boiler operating conditions, the SO_2 removal performance of a sodium scrubber depends on two main factors: the amount of scrubbing liquid circulated through the scrubber (this is termed the liquid-to-gas ratio or L/G) and the sorbent feed rate. Although design L/G ratios are dependent on the type of gas-liquid contactor used by the process vendor, sodium scrubbing systems have relatively low L/G ratios due to the high reactivity of the sodium alkali. Sodium scrubbing L/G's are generally in the range of 1.3 to $3.4 \ell/m^3$ (10 to 25 gal/1000 ft^3) whereas typical L/G's for lime and limestone scrubbers are in the range of 5 to $15 \ell/m^3$ (35 to 100 gal/1000 ft^3).[61]

The amount of fresh sorbent added to the system should be sufficient to replace the spent sorbent discharged with the process waste-water stream. If insufficient sorbent is added, the SO_2 removal performance of the scrubber will decrease. If more than the required amount of sorbent is added, its concentration will build-up in the system and may eventually result in chemical scale. In addition, adding too much fresh sorbent will increase process operating costs. A pH controller is used to monitor the sorbent feed rate. A pH measurement below a specified set point will result in an increase in the sorbent rate whereas a high pH measurement will decrease the sorbent feed rate.

4.2.2 Double Alkali

The double or dual alkali process uses a clear sodium alkali solution for SO_2 removal and produces a calcium sulfite and sulfate sludge for disposal. Although double alkali processes produce a throwaway byproduct, a regeneration step is employed to regenerate the active alkali for SO_2 sorption.

4.2.2.1 Process Description

4.2.2.1.1 System. The double alkali processes developed in the U.S. use lime as the calcium alkali, but other processes developed in Japan and still in the development stage in the U. S. use limestone.[62] A simplified flow diagram of a typical double alkali system is given in Figure 4.2-2. The process can be divided into three principal areas: absorption, regeneration, and solids separation. The principal chemical reactions for a sodium/lime double alkali system are illustrated by the following equations:[62]

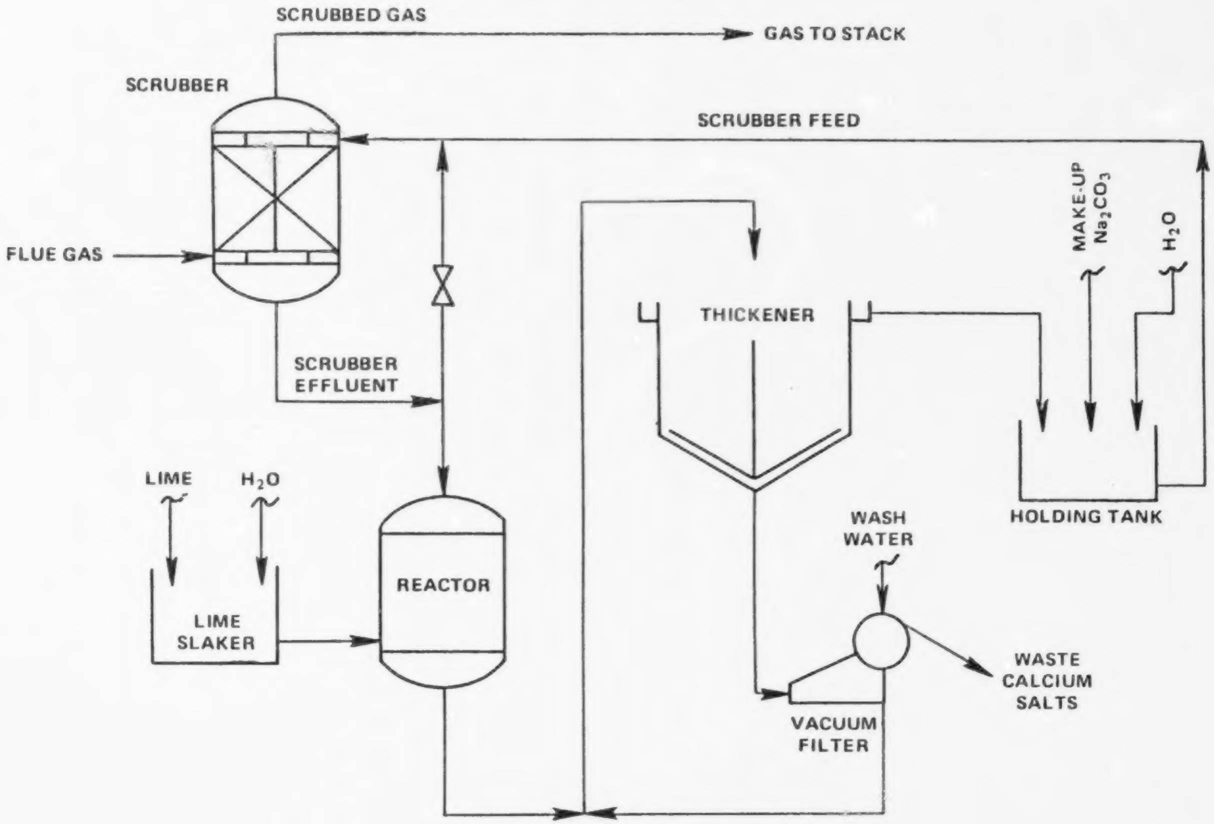
SCRUBBED GAS
GAS TO STACK
SCRUBBER
SCRUBBER FEED
FLUE GAS
MAKE-UP Na_2CO_3
H_2O
THICKENER
SCRUBBER EFFLUENT
LIME
H_2O
HOLDING TANK
WASH WATER
REACTOR
LIME SLAKER
WASTE CALCIUM SALTS
VACUUM FILTER

Figure 4.2-2. Simplified flow diagram for a sodium/lime double-alkali process.[63]

Absorption

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \qquad (4.2.2\text{-}1)$$

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (4.2.2\text{-}2)$$

$$Na_2SO_3 + 1/2\ O_2 \rightarrow Na_2SO_4 \qquad (4.2.2\text{-}3)$$

Regeneration

$$Ca(OH)_2 + 2NaHSO_3 \rightarrow Na_2SO_3 + CaSO_3\ 1/2\ H_2O + 3/2\ H_2O \qquad (4.2.2\text{-}4)$$

$$Ca(OH)_2 + Na_2SO_3 + 1/2\ H_2O \rightarrow 2NaOH + CaSO_3\ 1/2\ H_2O(s) \qquad (4.2.2\text{-}5)$$

$$Ca(OH)_2 + Na_2SO_4 + 2H_2O \rightarrow 2NaOH + CaSO_4\ 2H_2O(s) \qquad (4.2.2\text{-}6)$$

In the scrubber, SO_2 is removed from the flue gas by reaction with NaOH and Na_2CO_3, according to Equations 4.2.2-1 and 4.2.2-2. Because oxygen is present in the flue gas, oxidation also occurs in the system, according to Equation 4.2.2-3. Most of the scrubber effluent is recycled back to the scrubber, but a slipstream is withdrawn and reacted with slaked lime in the regeneration reactor according to reactions 4.2.2-4, 4.2.2-5, and 4.2.2-6. The presence of sulfate in the system is undesirable in that it converts active sodium to an inactive form, thus lowering SO_2 removal or increasing sodium consumption for a fixed SO_2 removal.

The regeneration reactor effluent, which contains calcium sulfite and sulfate is sent to a thickener where the solids are concentrated. The thickener overflow is returned to the system, and the underflow containing the calcium solids is further concentrated in a vacuum filter (or other device) to about 50 percent or greater solids content. The solids are washed, to reduce the soluble sodium salts in the adherent liquor prior to disposal, and the wash water is returned to the scrubber.[64]

4.2.2.1.2 Development status. Several process vendors currently offer double alkali systems commercially in the United States. Double alkali systems are currently operating or planned for use at ten industrial boiler sites, with the smallest application treating 230 Nm^3/min (8100 scfm) and the largest treating 8640 Nm^3/min (305,000 scfm) of gas.[65] Table 4.2-2 presents a summary of double alkali scrubbing systems applied to U. S. industrial boilers.

4.2.2.1.3 Applicability to industrial boilers. A potential limitation of this technology, although not as severe as with the once through sodium systems, is the need to dispose of the solid waste byproduct. The waste consists of calcium sulfite and sulfate salts and generally contains from 30 to 50 weight percent water. Because of the high concentration of soluble species in the scrubbing solution, the wastes will also contain soluble salts (such as Na_2SO_3, Na_2SO_4, and NaCl) as well as the relatively insoluble calcium salts. However, the soluble salts content of the waste can be reduced to less than 1 weight percent when the waste is washed to recover the sodium.[66]

4.2.2.1.4 Reliability/operability. Since there are few double alkali systems with long-term operating histories in the U. S., it is difficult to assess the overall reliability of this technology. A limited amount of data has, however, been reported in the EPA Industrial Boiler FGD Survey for seven different industrial boiler sites, and that data indicates that reported double alkali system reliability averages slightly higher than 90 percent.[67]

4.2.2.2 Factors Affecting Performance. Fuel characteristics such as the sulfur and chlorine content can have major impacts on the design and operation of a double alkali system. Major operating variables include the L/G ratio and alkali addition rate.

Combustion of low sulfur coal results in a higher ratio of oxygen to sulfur dioxide in the flue gas than does combustion of high sulfur coal. The high relative oxygen content promotes the oxidation of a high percentage of sodium sulfite to sodium sulfate. Since sodium sulfate does not react with hydrated lime in the presence of sodium sulfite, some active sodium is

TABLE 4.2-2. SUMMARY OF OPERATING AND PLANNED INDUSTRIAL BOILER DOUBLE ALKALI SYSTEMS[65]

Installation/Location	Vendor or Developer	Size (SCFM)	No. of FGD Units	Fuel Type	Fuel %S	SO_2[(1)] Inlet (ppm)	SO_2[(1)] Removal (%)	Waste Disposal
ARCO Polymers Monaca, PA	FMC	305,000	3	C	3	1800	90	Landfill
Caterpillar Tractor Co. East Peonia, ILL	FMC	210,000	4	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Juliet, ILL	ZURN	67,000	2	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Mapleton, ILL	FMC	236,000	5	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Morton, ILL	ZURN	38,000	2	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Mossville, ILL	ZURN	140,000	4	C	3.2	2000	90	Landf
Firestone Tire and Rubber Pottstown, NY	FMC	8070	1	C	2.5-3.0	1000	90.5	Landfill
General Motors, Corp. Parma, OH	G.M.	128,400	1	C	2.5	800-1300	90	Landfill
Grissom Air Force Base Bunker Hill, IN	Neptune/ Airpol	32,000	1	C	3.0-3.5	--------	--	Landfill
Santa Fe Energy Corp. Bakersfield, CA	FMC	70,000	1	0	1.5	710	96	Landfill

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(1) Inlet SO_2 and percent SO_2 removal are as reported to PEDCo by FGD system operators. Values reported may represent anything from single point wet chemical determinations to continuous monitoring results. Methods used to determine the values reported may or may not be EPA approved.

lost in the regeneration step. This loss has the same effect as reducing the sodium alkali feedrate. Oxidation can be minimized in low sulfur fuel (<1 percent S) applications by using a dilute absorbing solution (active sodium concentration less than 0.15 Molar). At the resulting low sulfite concentrations, the sulfate will react with calcium to regenerate the scrubbing liquor. For higher sulfur applications, (>1 percent S) oxidation can be minimized by using a concentrated absorbing solution (active sodium concentration greater than 0.15 Molar) and sulfate can be coprecipitated with calcium sulfite.[68]

Chlorides absorbed from the flue gas are difficult to remove and can cause problems if they build up in the system. The only mechanism for chlorides to leave the system is in the liquor contained with the solid waste. However, chlorides are recovered and recycled to the absorber when the waste is washed to recover sodium. In addition to decreasing the concentration of active alkali in the absorber, high levels of chlorides can result in stress corrosion. A solution proposed by one vendor is to use a prescrubber to remove chlorides before the double alkali system.[69] The use of a prescrubber with a separate liquor loop, however, could cause water balance problems in the system. Since all the evaporation loss would occur in the prescrubber, the only water loss from the double alkali system would be the water occluded with the solid waste. This small water loss would not allow enough water addition for the normal cake washing (more than one displacement wash), demister washing, pump seals, and lime slaking.[70]

The effects of variable L/G, pH, and pressure drop on double alkali process operation are shown in Figures 4.2-3 and 4.2-4 respectively. Figure 4.2-3 illustrates the increase in SO_2 removal performance due to increased L/G. Typical double alkali L/G's range from about 1.3 to $3.4 \ell/m^3$ (10 to 25 gal/1000 ft^3). The effects of pH are shown in Figure 4.2-4. The operating pH of the system can be adjusted by changing the sorbent feed rate and/or adjusting the pH of the regenerated liquor. In general, as shown by Figure 4.2-4, SO_2 removals decrease rapidly below pH 6. High pH levels (pH 9 or above) will result in calcium carbonate formation which can result

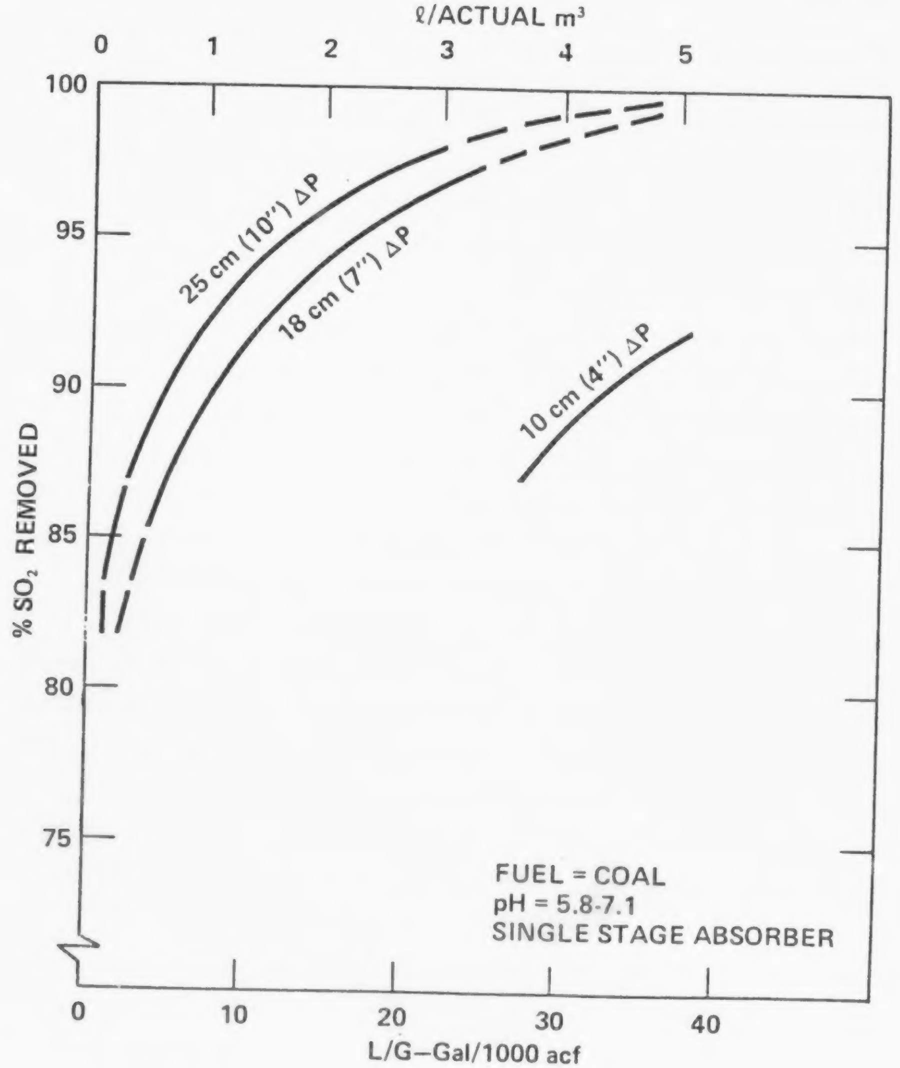

Figure 4.2-3. SO_2 removal versus L/G ratio for the Envirotech/Gadsby Pilot Plant with a single stage polysphere absorber.[71]

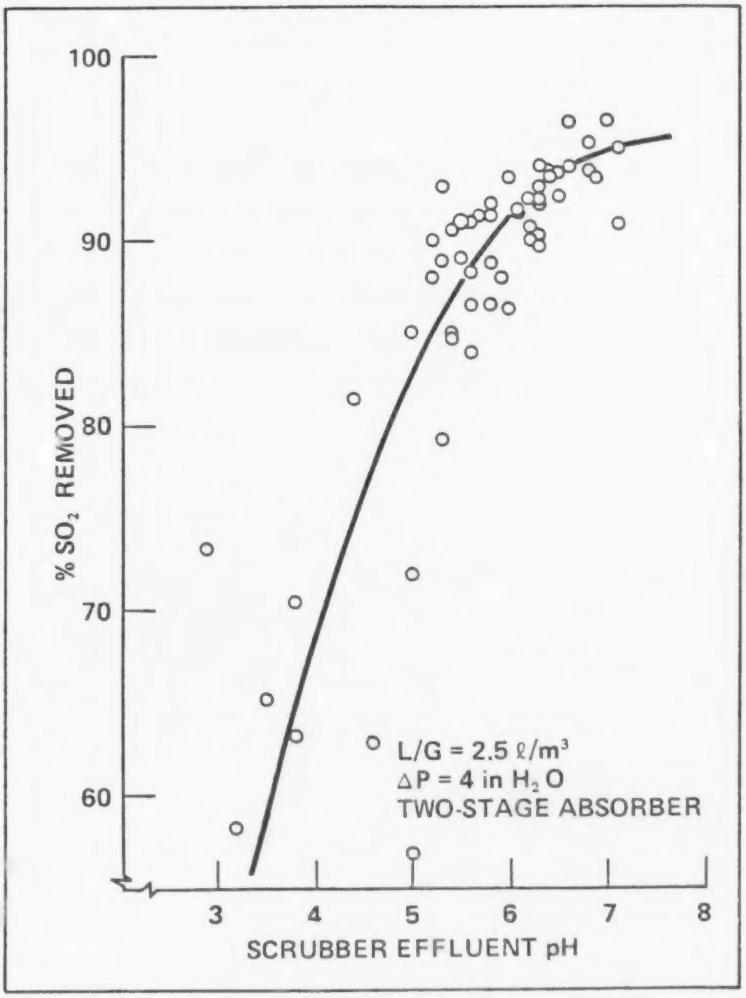

Figure 4.2-4. SO_2 removal versus scrubber effluent pH for the Envirotech/Gadsby Pilot Plant with a two-stage absorber.[72]

in scale formation. Consequently, the operating pH of double alkali systems is generally in a range of pH 6 to 8.[68]

4.2.3 Lime and Limestone

The lime and limestone FGD processes use a slurry of calcium oxide or calcium carbonate to absorb SO_2 in a wet scrubber. A calcium sulfite/sulfate sludge is produced for disposal.

4.2.3.1 Process Description

4.2.3.1.1 System. The absorption of SO_2 from flue gases by a lime or limestone slurry involves both gas-liquid, and liquid-solid mass transfer. The chemistry is complex, involving many side reactions. The overall reactions are those of SO_2 with lime (CaO) or limestone ($CaCO_3$) to form calcium sulfite ($CaSO_3$ 1/2 H_2O) with some oxidation of the sulfite to form calcium sulfate ($CaSO_4$ $2H_2O$). These reactions can be represented as follows:

Lime

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O \qquad (4.2.3\text{-}1)$$

$$SO_2 + 1/2\ O_2 + CaO + 2H_2O \rightarrow CaSO_4\ 2H_2O \qquad (4.2.3\text{-}2)$$

Limestone

$$SO_2 + CaCO_3 + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O + CO_2 \qquad (4.2.3\text{-}3)$$

$$SO_2 + 1/2\ O_2 + CaCO_3 + 2\ H_2O \rightarrow CaSO_4\ 2H_2O + CO_2 \qquad (4.2.3\text{-}4)$$

The calcium sulfite and sulfate crystals precipitate in a reaction vessel or hold tank which is designed to provide adequate residence time for solids precipitation as well as for dissolution of the alkaline additive. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slip stream from the hold tank is sent to a solid-liquid separator to remove the precipitated solids from the system. The waste solids, which may vary from

35-70 weight percent solids, are generally disposed of by ponding or landfill. A simplified flow diagram is presented in Figure 4.2-5.

Auxiliary equipment associated with this process includes a reagent preparation system. Reagent preparation may consist of limestone grinding and/or lime production. However, for most industrial boilers, due to their small size, preground lime and limestone may be purchased and the feed preparation system will then consist of storage silos and either lime slaking or limestone slurrying equipment.

Addition of adipic acid to the FGD slurry can enhance SO_2 removal and improve the reliability and economics of lime and limestone FGD systems. Adipic acid addition provides a buffering action which limits the drop in pH that normally occurs at the gas/liquid interface during SO_2 absorption. This stabilized pH results in an increased mass transfer rate of SO_2 into the liquid phase. In addition, the capacity of the scrubbing liquor available for reaction with SO_2 is increased by the formation of calcium adipate in solution.[74] Adipic acid addition also increases lime or limestone utilization. As a result, limestone grinding requirements and solid waste generation are somewhat lower than those for a conventional limestone FGD system.[75]

4.2.3.1.2 Development status. Both lime and limestone FGD technology is demonstrated and commercially available. Lime FGD technology was first used to control SO_2 emissions on commercial boiler pilot plants in England about 40 years ago.[76] As shown by Table 4.2-3, there are currently two operating systems on industrial boilers in the U. S.; one lime system treating 2380 Nm^3/min (84,000 scfm) of gas, and one limestone system treating 1560 Nm^3/min (55,000 sfcm) of gas.[78]

In addition to industrial boiler use, some 34,000 MW_e of coal-fired electrical generating capacity in the United States has been committed to lime or limestone scrubbing. This figure includes 28 facilities in operation, 35 under construction, and another 16 in the planning stages (i.e., contract awarded, letter of intent signed, or requesting/evaluating bids).[76]

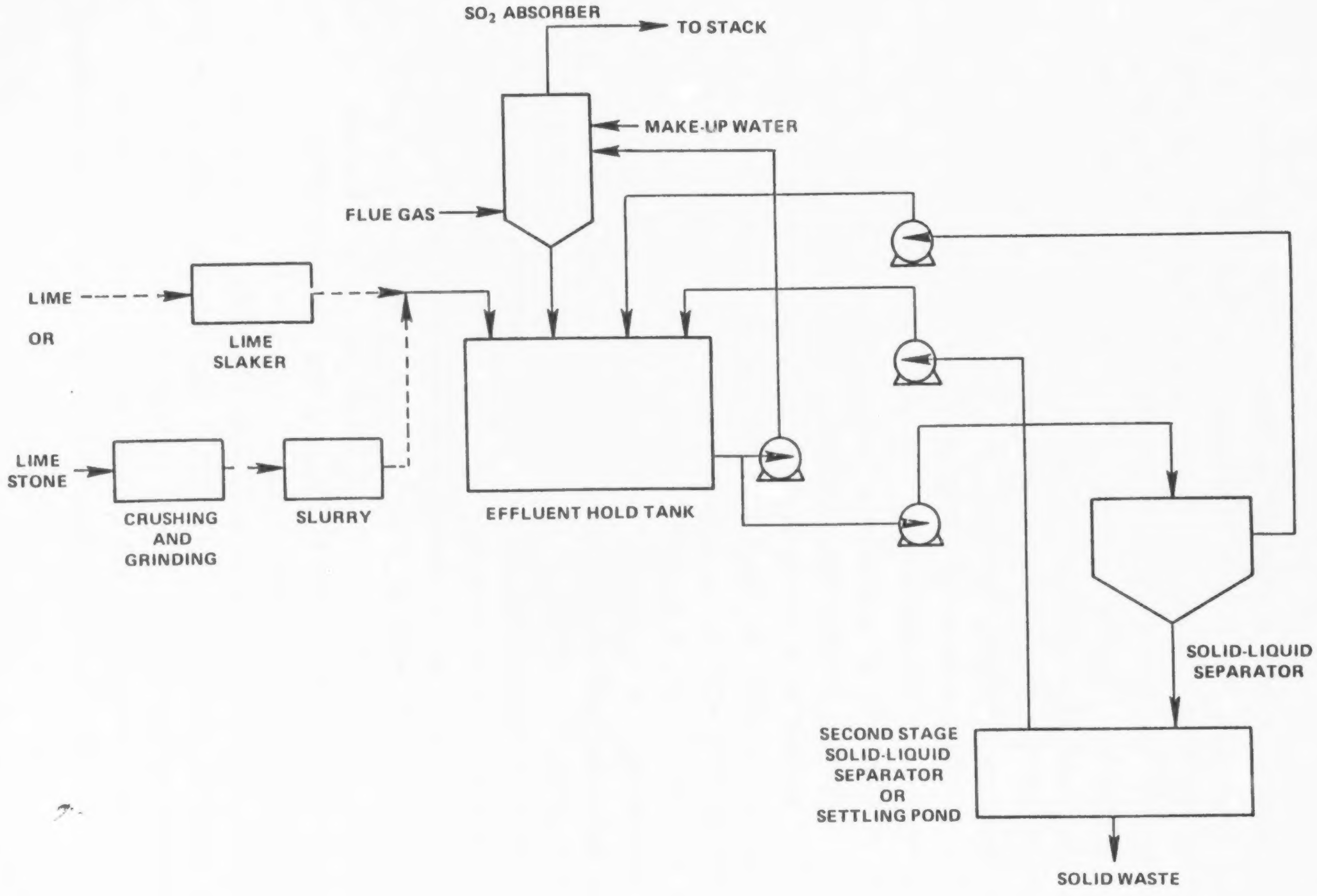
SO$_2$ ABSORBER
TO STACK
MAKE-UP WATER
FLUE GAS
LIME
OR
LIME SLAKER
LIME STONE
CRUSHING AND GRINDING
SLURRY
EFFLUENT HOLD TANK
SOLID-LIQUID SEPARATOR
SECOND STAGE SOLID-LIQUID SEPARATOR OR SETTLING POND
SOLID WASTE

Figure 4.2-5. Process flow diagram for a typical lime or limestone wet scrubbing system.[73]

TABLE 4.2-3. SUMMARY OF OPERATING LIME AND LIMESTONE SYSTEMS FOR U.S. INDUSTRIAL BOILERS AS OF MARCH 1978[77]

Process	Vendor	Company/Location	New or retrofit	Size scfm	Fuel	
					Type	Sulfur (%)
Lime	Koch Engineering	Armco Steel Middletown, OH	R	84,000	Coal	0.8
Lime and Limestone	Research Cottrell-Bahco	Rickenbacker Air Force Base Columbus, OH	R	55,000	Coal	3.6

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[a] 90 percent design SO_2 removal with lime, lower with limestone.

Emission test results from an EPA test facility at the Shawnee Power Station in Paducah, Kentucky have demonstrated an average SO_2 removal of 97 percent for an industrial boiler-size, adipic acid enhanced, venturi/FGD system. A 30 day test at the Rickenbacher AFB in Columbus, Ohio demonstrated an average SO_2 removal efficiency of 94 percent for an adipic acid enhanced limestone FGD system. This test is discussed in more detail in Section 4.2.5 and complete test data are presented in Appendix C. A demonstration of this technology on a full scale utility boiler is currently underway at Springfield City Utilities' Southwest Power Plant.

4.2.3.1.3 Applicability to industrial boilers. Both lime and limestone processes are applicable to industrial boilers. The processes use readily available moderate priced sorbents. As with the double alkali process, a potential limitation of the lime and limestone processes is the requirement for disposal of the waste sludge byproduct. While the problem associated with the presence of highly soluble salts in the waste is much less severe than for the double alkali or once through sodium processes, the increased land requirements associated with scrubber sludge disposal could be limiting for some applications and must be evaluated on a site specific basis.

The presence of adipic acid on the EPA's hazardous materials list should not exclude its use as an FGD additive. Bioassay tests run on sludge samples from the Shawnee facility show no significant difference in toxicity between adipic acid enhanced system sludge and sludge samples from systems without adipic acid. Additional studies on leachate toxicity have indicated that sludge generated from systems using adipic acid show toxicity to be well within EPA limits.[79]

4.2.3.1.4 Reliability/operability. Reliability of lime and limestone FGD systems for industrial boiler applications is difficult to assess since there are only two installed systems and only one of those, the Bahco system located at Rickenbacker Air Force Base (RAFB), has been operational over a long period of time. Scrubber performance at the RAFB facility has generally been quite good except for the early stages of operation in which several startup problems resulted in significant amounts of downtime. From

November 1976 through December 1978, the RAFB system demonstrated that an industrial boiler FGD system can operate with high reliability as it operated 95 percent or more of the time during that period except for the months of January, February and March 1978. During those three months, system downtime was caused by a severe blizzard which resulted in the freeze-up of several lines.[80] This problem can be mitigated or avoided by insulating exposed lines and by keeping the slurry circulating through the lines whenever possible during periods of downtime in severely cold weather.

4.2.3.2 Factors Affecting Performance. The removal of SO_2 from industrial boiler flue gas in a lime or limestone FGD system involves a gas-liquid-solid mass transfer process and thus is more complex than the once through sodium or double alkali FGD systems which involve only gas-liquid mass transfer in the scrubbing step. As a rule, a large portion of the alkalinity required for SO_2 removal in lime and limestone systems is derived from solids dissolution in the scrubber. Since solid-liquid reactions tend to be significantly slower than do liquid-liquid reactions, it is advantageous to minimize the amount of solids dissolution required by maximizing the amount of liquid phase alkalinity in the scrubber feed liquor. For this reason systems which operate with high magnesium and sodium concentrations but low chloride levels exhibit higher SO_2 removals than systems which are lower in soluble alkalinity.[81]

Gas maldistribution can be a major problem in lime and limestone FGD systems, particularly in large units. Unlike once through sodium and double alkali systems, lime and limestone FGD systems normally utilize "open" contactors such as spray chambers. While this practice helps to minimize potential scaling and plugging problems often associated with lime and limestone systems, it is susceptible to gas distribution problems. Portions of the scrubber can become liquid phase alkalinity- limited due to gas maldistribution even though the total alkalinity entering the scrubber is sufficient for good SO_2 removal. Scrubber design should therefore incorporate straightening vanes and/or open packing to promote good gas distribution.[82]

Several design and operating variables should be considered in the design of a lime or limestone FGD process. The effects of the following major variables on SO_2 absorption efficiency and/or overall process operations are briefly discussed:

L/G Ratio - Higher SO_2 removal efficiencies are achieved at higher L/G ratios up to the point where flooding and poor gas distribution occurs.[82] Typical L/G's range from 5-15 ℓ/m^3 (35-100 gal/1000 ft^3).

Slurry pH - Higher SO_2 removal efficiencies are achieved with higher pH levels. Since scaling can occur at high pH's (pH greater than 9) typical control points for a lime system are in the pH 8-9 range. Because limestone systems are buffered, they typically operate in the pH 5-6 range.[83]

Effects of Soluble Species - The concentration of dissolved ions in the scrubbing slurry directly affects the liquid phase alkalinity and hence the system's ability to remove sulfur species from flue gas. For a given set of operating conditions, high concentrations of Na+ and Mg++ will improve the SO_2 removal efficiency and high concentrations of Cl will reduce it.[84]

Ash Removal - Although fly ash can be removed simultaneously with SO_2, the trend has been to remove it upstream for the following reasons: to decrease erosion in the scrubber and associated equipment such as pumps, piping, nozzles, and fans; to provide dry fly ash for sludge fixation; and to avoid particulate emission excursions during periods of scrubber inoperation.[85]

Oxidation - Forced oxidation systems increase the amount of calcium sulfate (gypsum) in the waste which is produced by sparging air into the system. A high sulfate sludge is more easily dewatered and has better structural properties than does the more difficult to handle thixiotropic calcium sulfite sludge.[86] Application of forced oxidation to FGD systems using adipic acid additive may result in degradation of the adipic acid in the slurry.

4.2.4 Dry Scrubbing

Dry scrubbing processes that appear to be applicable to industrial boilers include spray drying of a lime or sodium sorbent, and firing of a pelletized or pulverized coal and limestone mixture. Each of these processes produce a dry waste product for disposal. The use of the coal/limestone fuel mixture is discussed in Section 4.6.

4.2.4.1 Process Description

4.2.4.1.1 System. In a spray drying process, flue gas is contacted with a solution or slurry of alkaline material in a vessel of relatively long residence time (5 to 10 seconds).[87] Generally the particulate matter (fly ash) has not been removed prior to entering the absorber, and the spray drying process acts as a combined particulate/SO_2 removal system. The flue gas SO_2 reacts with the alkali solution or slurry to form liquid phase salts which are dried to about one percent free moisture by the heat in the flue gas. These solids, along with fly ash are entrained in the flue gas and carried out of the dryer to a particulate collection device such as an ESP or baghouse. Systems using a baghouse for particulate removal report additional SO_2 sorption occurring in the baghouse. A generalized diagram for a typical spray drying process is shown in Figure 4.2-6.

Reaction between the alkaline material and flue gas SO_2 proceeds both during and following the drying process. The mechanisms of the SO_2 removal reactions are not well-understood. It has not been determined whether SO_2 removal occurs predominantly in the liquid phase, by absorption into the finely atomized droplets being dried, or by reaction between gas phase SO_2 and the slightly moist spray-dried solids. The overall chemical reactions for this process are shown below.[89]

$$SO_2 + Na_2\,CO_3 \rightarrow Na_2SO_3 + CO_2 \tag{4.2.4-1}$$

or

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O \tag{4.2.4-2}$$

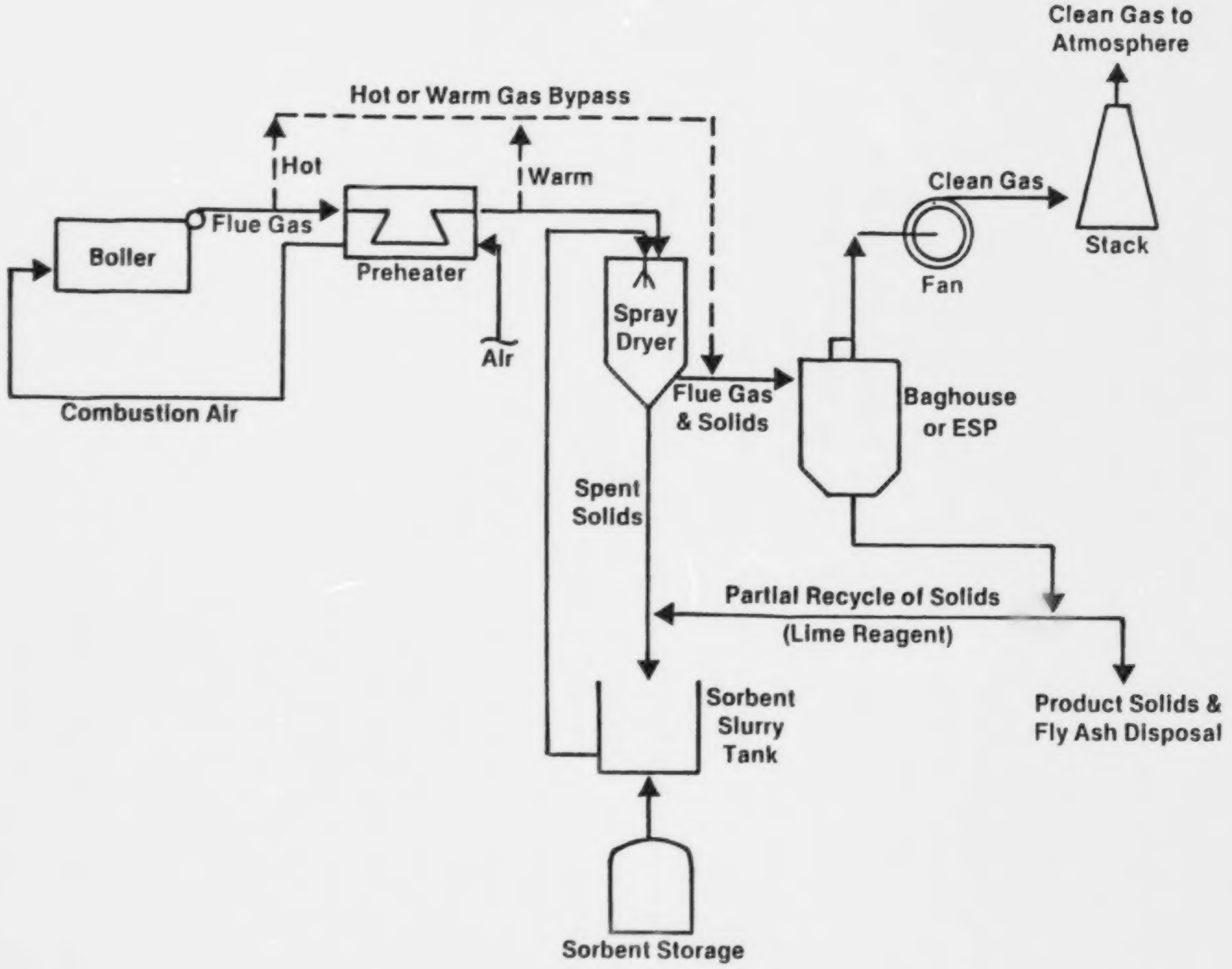
Clean Gas to Atmosphere
Hot or Warm Gas Bypass
Hot
Warm
Clean Gas
Stack
Boiler
Flue Gas
Preheater
Fan
Spray Dryer
Air
Flue Gas & Solids
Baghouse or ESP
Combustion Air
Spent Solids
Partial Recycle of Solids
(Lime Reagent)
Sorbent Slurry Tank
Product Solids & Fly Ash Disposal
Sorbent Storage

Figure 4.2-6. Typical spray dryer/particulate collection process flow diagram.[88]

In addition to these primary reactions, sulfate salts will be produced by the following reactions:

$$Na_2SO_3 + 1/2\ O_2 \rightarrow Na_2SO_4 \qquad (4.2.4\text{-}3)$$

$$SO_3 + Na_2CO_3 \rightarrow Na_2SO_4 + CO_2 \qquad (4.2.4\text{-}4)$$

or

$$SO_2 + CaO + 1/2\ O_2 + 2H_2O \rightarrow CaSO_4\ 2H_2O \qquad (4.2.4\text{-}5)$$

Liquid to gas (L/G) ratios for spray drying are typically 0.03 to 0.04ℓ/m^3 (0.2 to 0.3 gal/1,000ft^3). This low liquid rate is not sufficient to saturate the gas. Gas exit temperatures are typically in the 65-93°C (150 to 200°F) range which provides a safe margin against water condensation.[90]

4.2.4.1.2 Development status. Spray drying technology for removing SO_2 from boiler flue gas has been limited to pilot-scale testing of industrial boiler sized systems [280 to 560 m^3/min (10,000 to 20,000 acfm)] at several utility locations burning low sulfur western coals. This technology is being commercially offered by several vendors, and five spray drying FGD systems have been sold for industrial boiler applications. These systems are being applied to boilers burning coals with a fairly wide range of sulfur contents (0.6 to 3.5 percent S). Table 4.2-4 summarizes the commercial spray drying systems sold for application to industrial boilers. In addition eleven full-scale utility systems have been sold. The utility systems are being applied to low sulfur (less than 2 percent) coal-fired units and SO_2 removal guarantees from the vendors are as high as 90 percent. However, it still remains to be shown whether spray dryer systems will be able to achieve high SO_2 removal efficiencies when applied to full scale industrial boiler installations firing a range of coal types.

4.2.4.1.3 Applicability to industrial boilers. Spray drying technology is an applicable SO_2 control method for all industrial boilers firing low to medium sulfur fuels (less than 3 percent sulfur). However,

TABLE 4.2-4. SUMMARY OF INDUSTRIAL BOILER SPRAY DRYING SYSTEMS 91

Company Location	Vendor	Sorbent	Size (lb steam/hr)	Fuel		SO_2 Removal Guarantee (%)[a]
				Type	% Sulfur	
Strathmore Paper Co. Woronoco, MA (operating)	Mikropol	Lime	85,000	Coal	2 to 2.5	75% on 3% S coal
Celanese Cumberland, MD (operating)	Wheelabrator-Frye/ Rockwell Int.	Lime	110,000	Coal	1 to 2	85% on 2% S coal
University of Minnesota Minneapolis, MN	Carborundum Environmental Systems, Inc.	Lime	2 units @ 120,000 acfm each	Coal	0.6 to 0.7	70%
Department of Energy Argonne, IL	Niro Atomizer, Inc./Joy-Western Precipitation Division	Lime	170,000	Coal	3.5	80% (1.2 lb $SO_2/10^6$ Btu)
Container Corp. Pittsburgh, PA	Ecolaire, Inc.	Lime	170,000	Coal	1	NA

NA = Not available.

[a] Vendor design guarantees under specific operating conditions.

the technical and economic viability of this process is not clear for applications requiring high SO_2 removals for coals containing greater than three percent sulfur.

The potential for condensation in downstream particulate collection equipment, especially during system upsets, is also a concern. Condensation problems may be avoided by bypassing the fabric filter during system upsets and by maintaining spray dryer outlet temperatures at an adequate margin above the adiabatic saturation point. The effects of condensation on downstream equipment and system performance using varying quality coals are questions that will be resolved only after additional operating experience is obtained in either utility or industrial boiler applications.

4.2.4.1.4 Reliability/operability. Since dry scrubbing is a relatively recent innovation in industrial boiler FGD, no data is available on the long-term commercial reliability or operability of these systems. However, since they are less complex mechanically and no more complex chemically than wet calcium or sodium-based scrubbing systems, they should ultimately prove to be at least as reliable and operable.

4.2.4.2 Factors Affecting Performance. The performance of a spray dryer FGD system depends on several factors, the two most important being the L/G and the stoichiometric ratio of sorbent to SO_2. Unlike a wet scrubbing system the amount of water that can be added (the L/G) is set by heat balance considerations for a given inlet flue gas temperature and approach to saturation. Typical L/G ratios range from 0.03 to 0.04 ℓ/m^3 (0.2 to 0.3 gal/1000 ft^3). The sorbent stoichiometry is varied by raising or lowering the concentration of a solution or slurry containing this set amount of water. As sorbent stoichiometry is increased to raise the level of SO_2 removal, there are two potentially limiting factors:[87]

- Sorbent utilization may decrease, raising sorbent and disposal costs per unit of SO_2 removed.
- An upper limit on the solubility of the sorbent in the solution, or on the weight percent of sorbent solids in a slurry may be reached.

Methods of circumventing these limitations include recycling sorbent, either from solids dropped out in the spray dryer or from the particulate collection device[92] and operating the spray dryer at a lower outlet temperature; that is, at a closer approach to saturation.[88]

Based upon pilot unit test results, high SO_2 removals (up to 90 percent) can be achieved for low-sulfur coal applications, using either lime or sodium-based sorbents. Stoichiometric ratios of 2.3 to 3.0 were required for lime operations whereas stoichiometric ratios of only 1.0 to 1.2 were required to achieve the same SO_2 removal for sodium operations. It has also been reported that 90 percent SO_2 removal may be achieved with a stoichiometric lime requirement of 1.3 to 1.7 by recycling some of the unreacted sorbent.[93] A sodium-based system should be able to achieve higher SO_2 removals than lime based systems on high sulfur coals due to the greater reactivity of sodium hydroxide or sodium carbonate compared to lime.

Spray dryer design can also be affected by the choice of the particulate collection device. Bag collectors may have an advantage over ESPs in that unreacted alkalinity in the collected waste on the bag surface can react with the remaining SO_2 in the flue gas. Some process developers have reported SO_2 removal on bag surfaces on the order of 10 percent.[94] A disadvantage of using a bag collector is that since the fabric is somewhat sensitive to wetting, a safe margin above the saturation temperature (on the order of 20 to 35°F) must be maintained for bag protection. Some vendors claim that ane ESP is less sensitive to condensation and hence can be operated closer to saturation (less than a 25°F approach) with associated increase in spray dryer performance. However, they feel that SO_2 removal within the collector is not likely to be as high as in a baghouse.[95]

4.2.5 Emission Reduction Data

This section presents continuous SO_2 emission monitoring data for five wet FGD systems and a lime spray drying system. Emission data for the wet FGD systems are representative of the SO_2 removal capability of well designed, operated and maintained industrial boiler FGD systems. All sampling and analyses were conducted in accordance with the procedures specified in 40 CFR 60 Appendix A.

As with the particulate matter emission data, tests not considered to be representative of well operated FGD systems are not presented in this chapter, but are included in Appendix C along with documentation of the reasons why they were not considered to be representative. Three such tests of wet FGD systems are discussed in Appendix C.

4.2.5.1 Emission Reduction Data for Wet FGD Systems. This section presents the results of five continuous SO_2 emission monitoring tests of industrial boiler wet FGD systems. All of the tests were conducted by EPA. Data were collected for two dilute double alkali systems, one sodium throwaway system, a lime system, and a limestone system with adipic acid addition. Table 4.2-5 summarizes the five test programs and daily average results are shown in Figures 4.2-7 to 4.2-11. Hourly results and detailed descriptions of tests procedures can be found in the references cited in the Appendix C discussions of each of the test sites. Figures 4.2-7 to 4.2-11 show the 24-hour average SO_2 removal, boiler load, and scrubbing slurry pH. Only days with 18 hours or more of test data are presented; missing days (days where 18 hours of data were not obtained are indicated by a break in data shown in Figures 4.2-7 to 4.2-11.

Table 4.2-5 shows that each system averaged more than 90 percent SO_2 removal over the test period. In addition, average outlet SO_2 concentrations for each test period were 192 ng/J (0.45 lb/10^6 Btu) or less.

Thirty days of continuous emissions data were gathered at the sodium throwaway scrubbing system at Location I. Figure 4.2-7 shows consistent high SO_2 removal, averaging 96.2 percent for the test period. Table 4.2-5 shows that daily average inlet SO_2 concentrations ranged from 1961 to 2480 ng/J (4.6 to 5.6 lb/10^6Btu). The scrubbing solution pH was consistently maintained at about pH 8. As discussed in Section 4.2.1.1, proper pH control is important maintaining the sorbent feed rate required for the desired SO_2 removal.

Figures 4.2-8 and 4.2-9 show daily average results for two similar double alkali systems at Location III. The two systems averaged 91.6 and 92.2 percent SO_2 removal over the respective 17- and 24-day test periods. Daily average inlet SO_2 concentrations ranged between 1235 and 2000 ng/J

TABLE 4.2-5. SUMMARY OF CONTINUOUS SO_2 EMISSION DATA AT FIVE INDUSTRIAL BOILER WET FGD SYSTEMS

			24-hr Average Results						
			Inlet SO_2 (ng/J)[c]		Outlet SO_2 (ng/J)[c]		% SO_2 Removal		
Location [a]	System Type	No. of Days of Data[b]	Range	Average[d]	Range	Average[d]	Range	Average[d]	Comments
I	Sodium Throwaway	30	1961-2480	2348	54-267	87	88-98	96	Tray & quench liquid scrubber; coal sulfur = 3.6%
III/No. 1	Double Alkali	17	1235-2000	1646	81-213	138	88-95	92	Two Tray scrubber; Design pH = 5.5 to 7.5; Design L/G = 2.7 ℓ/m^3;
III/No. 3	Double Alkali	24	1180-2285	1606	37-446	128	74-97	92	Same design as Location III/#1.
IV	Lime	29	1927-2432	2250	94-294	192	88-96	91	Two "inverted venturi" stages; Coal Sulfur = 3.5%.
IV	Limestone with Adipic Acid Addition	30	1333-2765	2125	56-262	122	90-97	94	Coal sulfur 2.2 to 3.5%; Adipic Acid concentrations of 1770 to 3000 ppm.

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[a] More complete descriptions, data testings, and references for test reports can be found in Appendix C.

[b] Only days with 18-hrs or more of test data are reported.

[c] Divide by 430 to convert to lb/10^6 Btu.

[d] Arithmetic mean of 24-hr averages for test period.

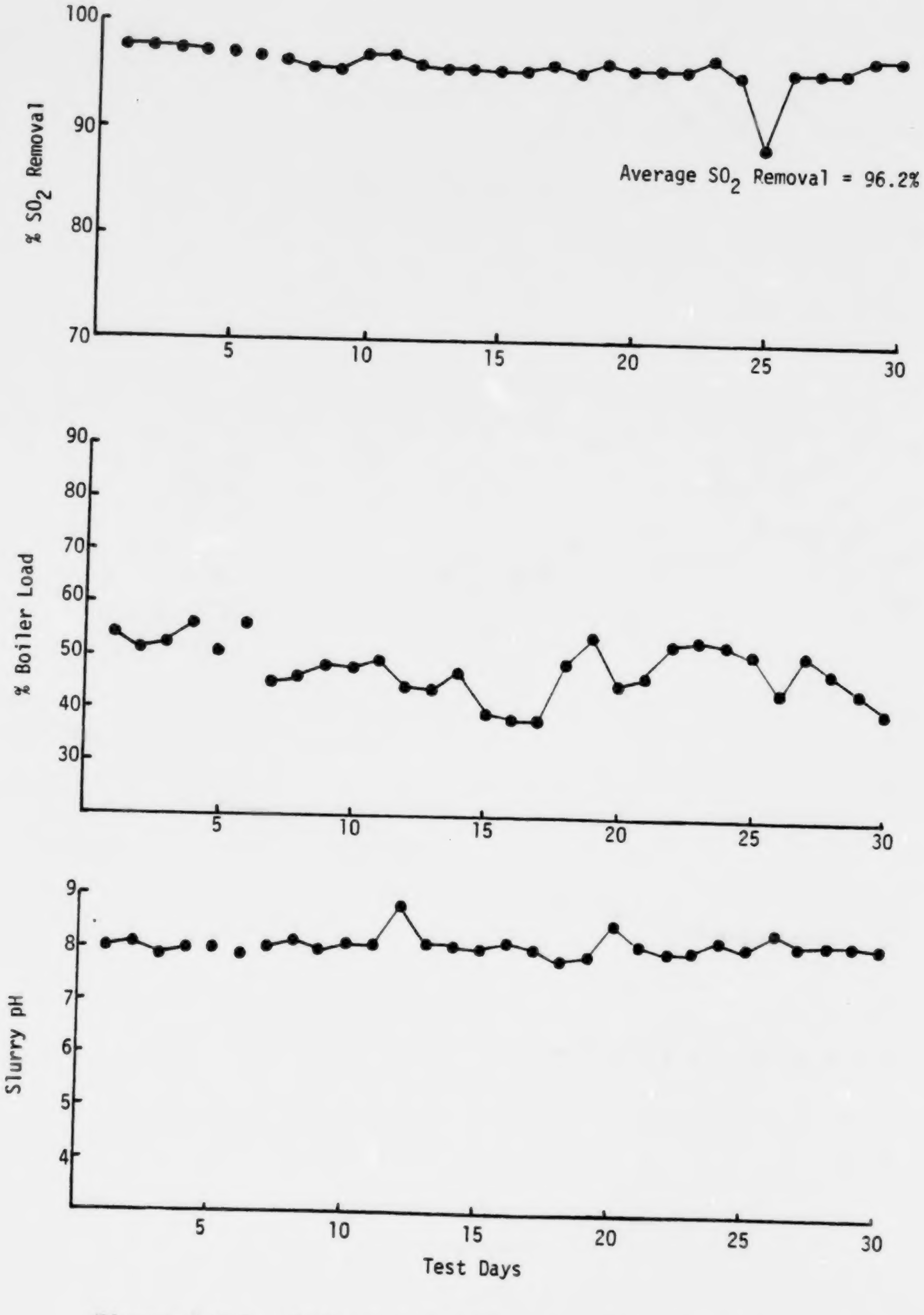


Figure 4.2-7. Daily average SO_2 removal, boiler load, slurry pH for the sodium scrubbing process at Location I.

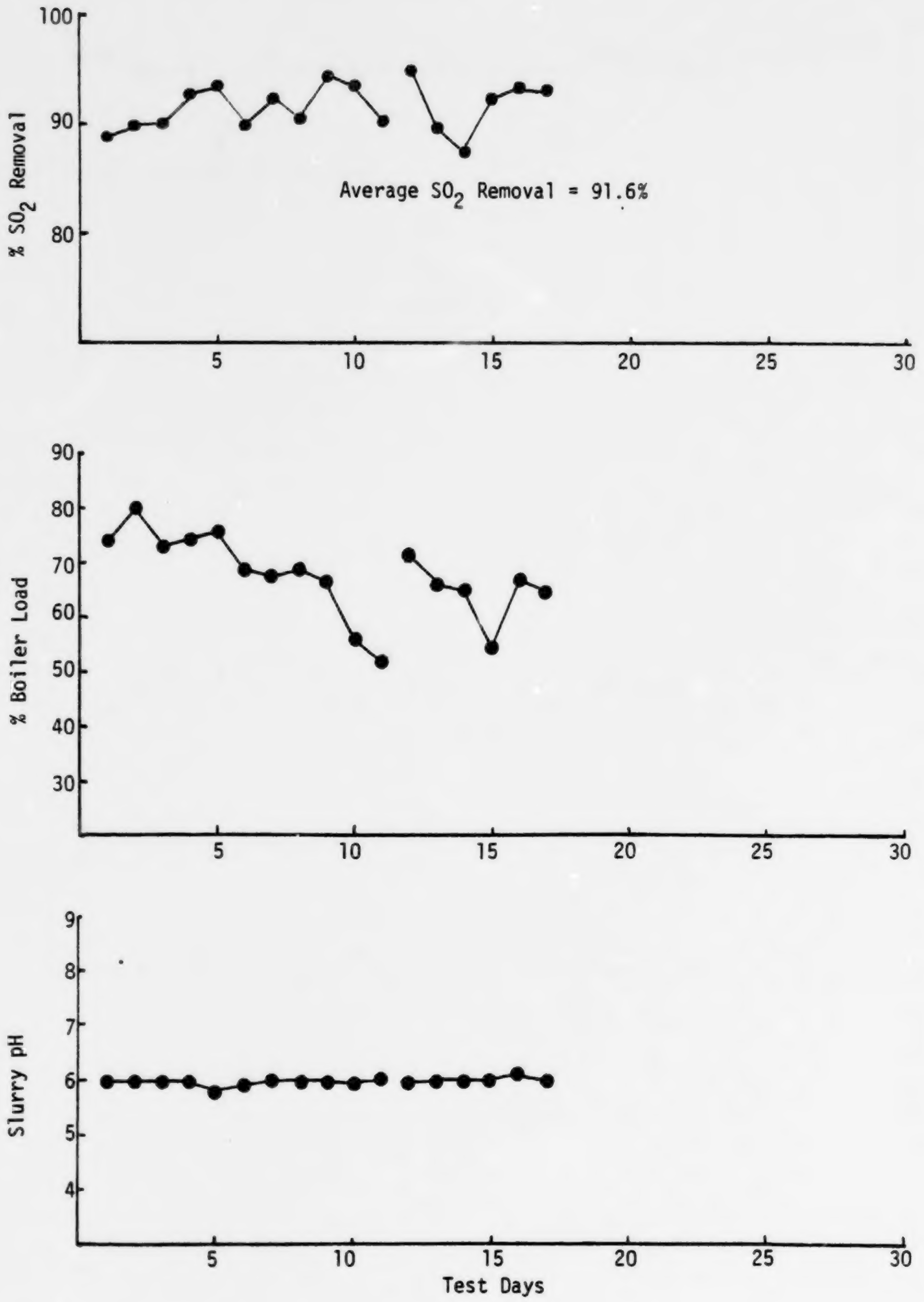


Figure 4.2-8. Daily average SO_2 removal, boiler load, and slurry pH for the dual alkali scrubbing process at Boiler No. 1, Location III.

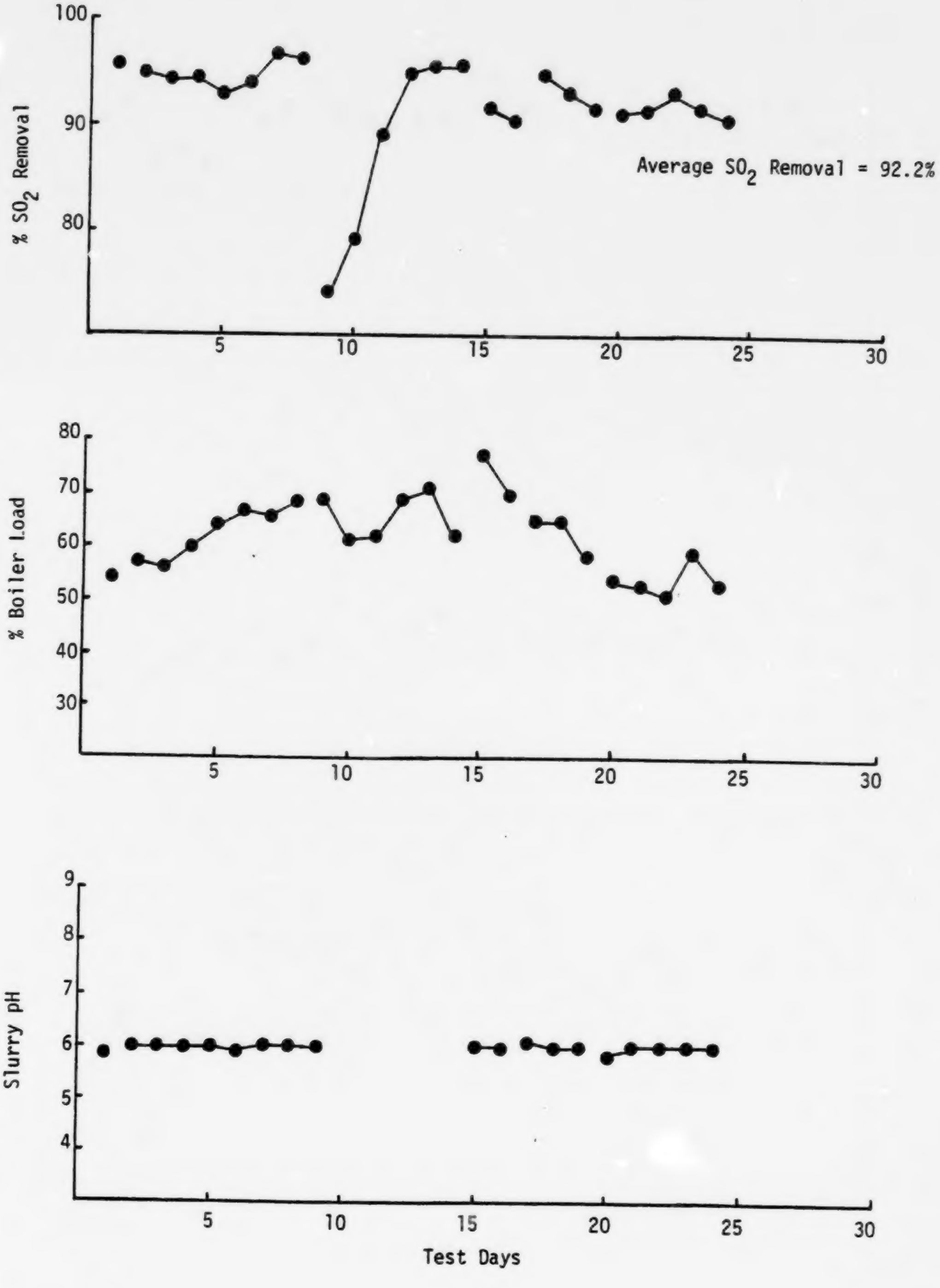


Figure 4.2-9. Daily average SO_2 removal, boiler load, and slurry pH for scrubbing process at Boiler No. 3 Location III.

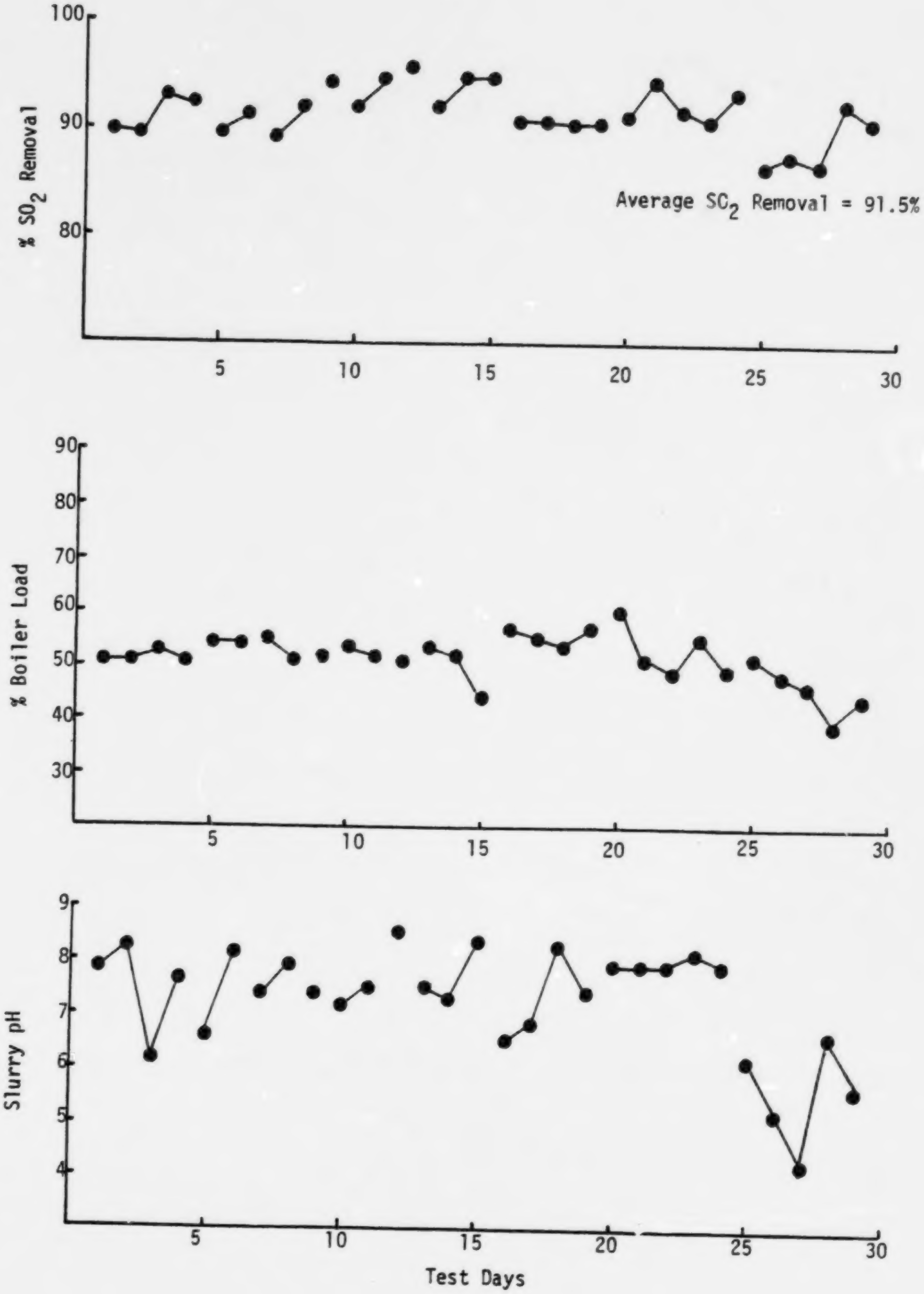


Figure 4.2-10. Daily average SO_2 removal, boiler load, and slurry pH for lime slurry scrubbing process at Location IV.

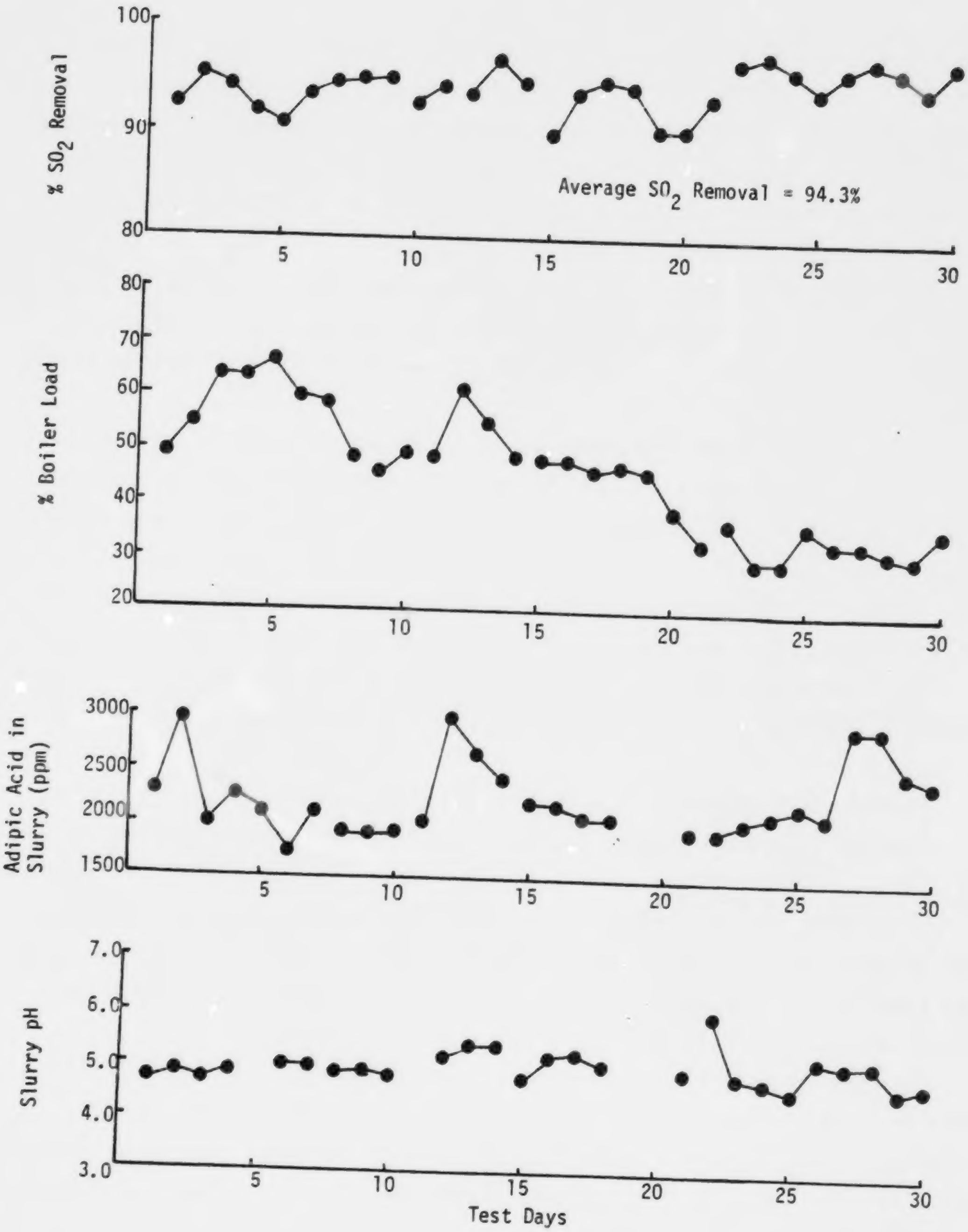


Figure 4.2-11. Daily average SO$_2$ removal, boiler load, adipic acid concentration, and slurry pH for limestone system at Location IV.

(2.9 and 4.7 lb/10^6 Btu) at Boiler No. 1 and between 1180 and 2285 ng/J (2.8 and 5.3 lb/10^6 Btu) at Boiler No. 3. The scrubbing slurry pH for both systems was maintained close to pH 6 during the test periods. The desired operating pH of most double alkali systems is pH 6 to 8 (Section 4.2.2). The design pH for the systems at Location III is pH 5.5 to 7.5 and the design L/G ratio is 2.7ℓ/m^3 (20 gal/10^3 ft^3).

The lowest SO_2 removals observed at Location III, Boiler No. 3 (Test days 9 and 10 in Figure 4.2-9) were during FGD system start-up after the scrubber had been taken off-line due to low boiler load requirements at the plant.

Figure 4.2-10 shows the daily average results of tests of a lime scrubbing system at Location IV. Average SO_2 removal for the period was 91.5 percent and daily average inlet SO_2 concentrations ranged between 1927 and 2432 ng/J (4.5 and 5.7 lb/10^6 Btu). The lowest SO_2 removals were observed during the last few days of testing when the scrubbing slurry pH dropped below pH 6. As discussed in Section 4.2.3, typical control points for lime systems are more often in the pH 8 to 9 range. Figure 4.2-10 shows generally higher SO_2 removals for the periods during which slurry pH was maintained near pH 8.

Figure 4.2-11 presents the results of 30-days of testing at Location IV during which limestone reagent was used (instead of lime) and adipic acid was added to the scrubbing solution. These data show an average SO_2 removal of 94.3 percent for the test period. High SO_2 removals were obtained over a wide range of boiler loads. Adipic acid concentrations in the slurry ranged from 1770 to 3000 ppm and slurry pH was maintained near pH 5. Inlet SO_2 concentrations ranged from 1333 to 2765 ng/J (3.1 to 6.4 lb/10^6 Btu).

The data in Figure 4.2-11 indicate that adipic acid addition contributes to high SO_2 removals and, with proper pH and adipic acid addition control, low variability in system performance. Previous testing of the FGD system at Location IV with limestone slurry had shown SO_2 removals between 50 and 70 percent. It should be noted that adipic acid addition may not have been solely responsible for the improved SO_2 removal efficiency since the limestone only tests appeared to have been conducted at conditions outside the design range of the system (See Appendix C).

4.2.5.2 Emission Reduction Data for Lime Spray Drying System. Figure 4.2.12 illustrates the daily average results for SO_2 emission monitoring of the lime spray drying system at Location VI. Removal efficiencies ranged from 46 to 80 percent. Inlet SO_2 removal efficiency averaged 68.4 percent over the test period. SO_2 concentrations averaged 1492 ng/J (3.5 lb/10^6Btu) and ranged from 1118 to 1905 ng/J (2.6 to 4.4 lb/10^6 Btu). Outlet concentrations had a range of 339 to 702 ng/J (0.8 to 1.6 lb/10^6Btu) while averaging 460 ng/J (1.1 lb/10^6Btu). Figure 4.2-12 shows SO_2 removal efficiencies averaging 75 percent on the days when average daily SO_2 concentrations were 1720 ng/J (4.0 lb/10^6 Btu) or greater. The somewhat variable performance of the spray dryer can be attributed in part to various system upsets that occurred throughout the testing period. These upsets include slurry pump problems, spray dryer plugging and boiler load fluctuations. Over the last six days of the testing program, a period in which no upsets occurred, the average daily SO_2 removal remained near 80 percent.[232]

The average sulfur content of the coal fired during the test was near 2 percent, which is the coal sulfur content the system was designed for. No data were available for spray drying systems applied to high sulfur coal-fired boilers.

4.3 COMBUSTION MODIFICATION TECHNIQUES FOR NITROGEN OXIDE (NO_x) CONTROL

NO_x emissions from industrial boilers are generally classified as one of two types:

- thermal NO_x (formed by the reaction of atmospheric nitrogen and oxygen in the combustion zone)
- fuel NO_x (formed by the reaction of fuel nitrogen and oxygen in the combustion zone).

NO_x includes both NO and NO_2. The latter species is typically about 5 percent of the total NO_x emissions, although some data indicates that the NO_2 fraction may be somewhat lower for coal- and oil-fired units than for gas-fired units.[97]

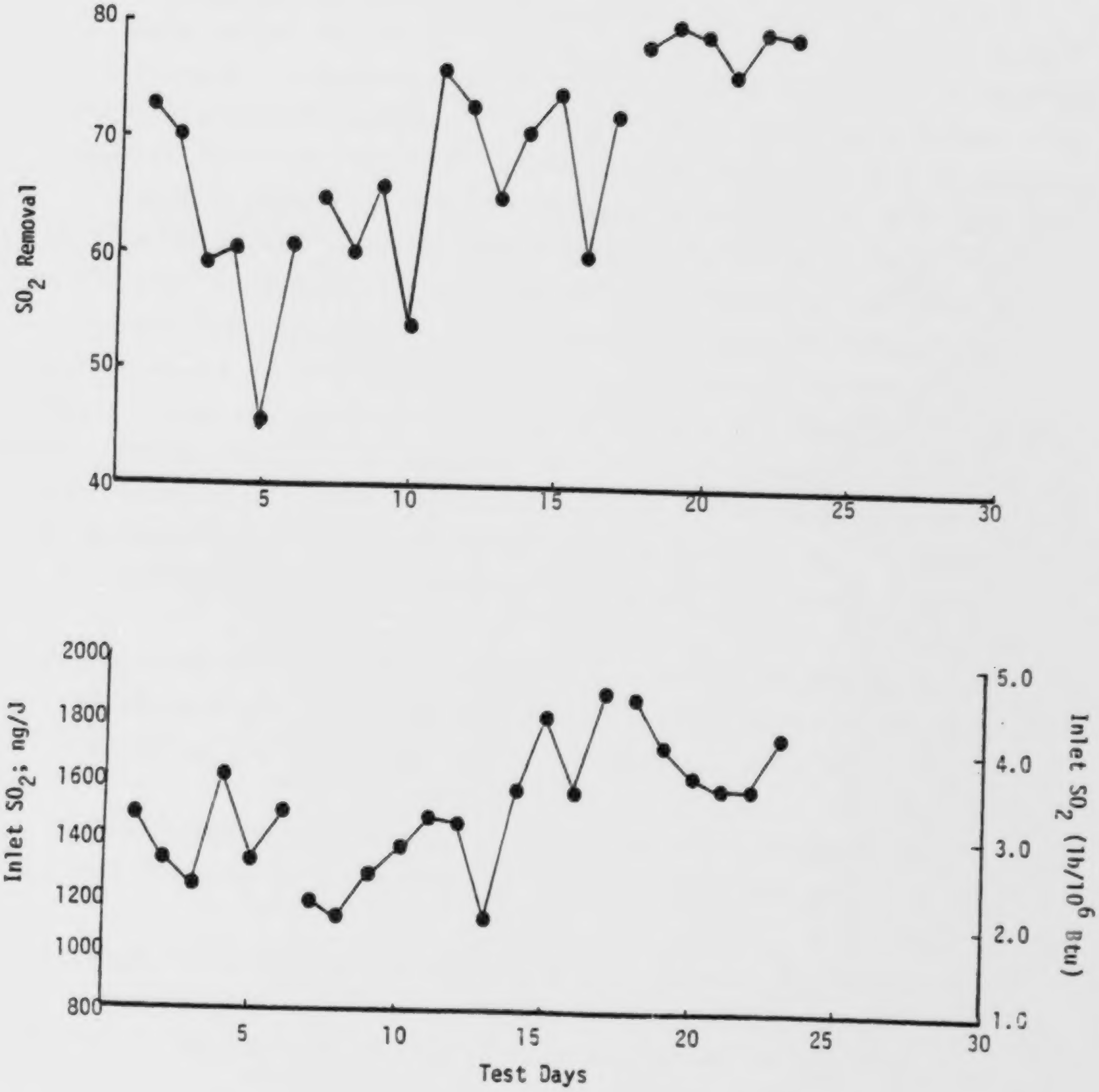


Figure 4.2-12. Daily average SO_2 removal, inlet SO_2 for lime spray system at Location VI.

The formation of thermal NO_x increases with increases in excess air, flame temperature, and residence time in the high temperature zone of the boiler.[96] Fuel NO_x formation occurs at a much lower flame temperature than those required to form thermal NO_x and thus emissions do not generally vary with flame temperature.

The rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and thus is amenable to suppression through modification of the combustion process. The following combustion modifications have been investigated as NO_x control measures for industrial boilers:

- Low excess air (LEA)
- Staged combustion (SC)
- Flue gas recirculation (FGR)
- Low NO_x burners (LNB)
- No combustion air preheat or reduced air preheat (RAP)
- Ammonia injection

The mechanism by which each of these techniques reduces NO_x formation and/or emissions, the applicability of the technique to new industrial boilers, the design or operating factors which influence the NO_x reduction performance of the control technique on an industrial boiler, and any impact these controls may have on the design and operation of the boilers is discussed in Subsections 4.3.1 through 4.3.6. Data of the type reported for FGD systems is not available for NO_x combustion modification reliability/operability. However, a number of qualitative factors or concerns which may impact the operability of these techniques are discussed in the following sections. Both short- and long-term performance data are available for LEA, SC, FGR, and RAP applied to various industrial boiler types and fuels. These data are presented and discussed in Subsection 4.3.7. No performance data for ammonia injection were available for operating commercial boilers.

4.3.1 Low Excess Air

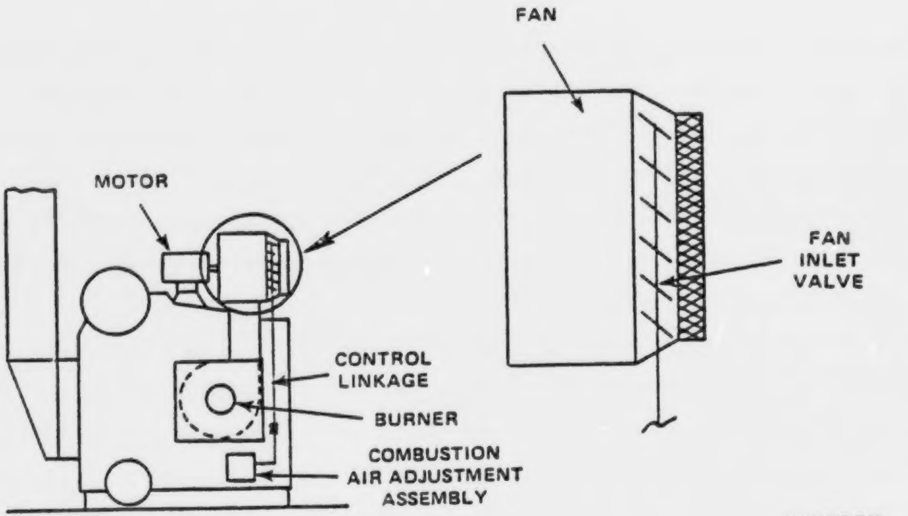
Burner and boiler manufacturers usually recommend the lowest excess air level consistent with safe operation and prevention of smoke for a given burner/boiler/fuel combination. However, industrial boilers normally operate with excess air levels above those recommended by the burner or boiler manufacturers. For example, a gas/oil burner designed to operate with 10 to 15 percent excess air often operates with 20 percent or more.[98] This additional combustion air provides a safety margin designed primarily to prevent smoke emissions during sudden load surges. It also allows for minimal operator supervision and simple combustion air control equipment. This additional excess air, however, provides extra oxygen to the flame zone, and results in increased NO_x formation. Excess air levels higher than the manufacturer's specification also reduce the thermal efficiency of the boiler by increasing the volume of heated gas released to the atmosphere.[99]

In low excess air (LEA) operation the primary combustion air flow is reduced; with less combustion air, both thermal and fuel NO_x formation are reduced.[100] In general, the further the excess air is reduced on a given boiler, the lower the NO_x emissions.[101]

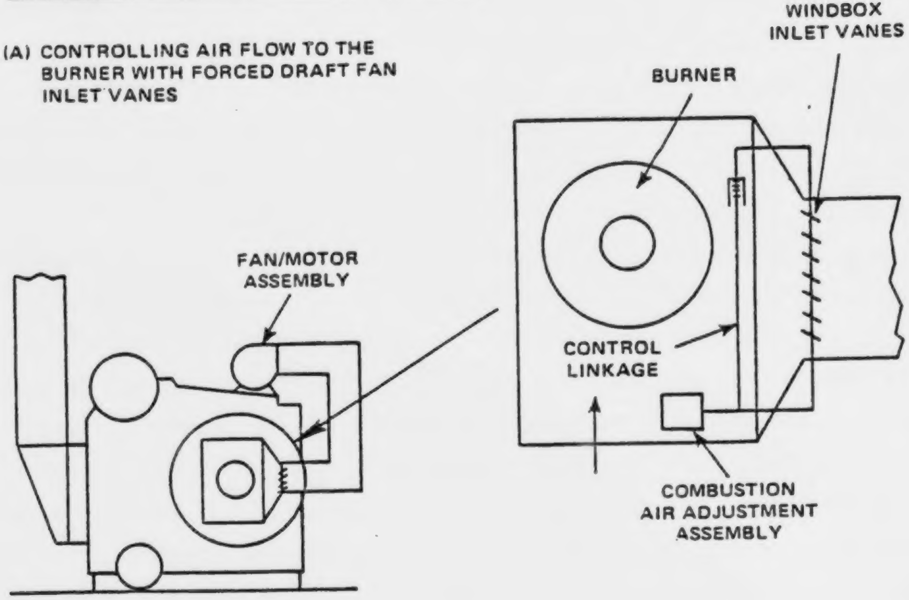
4.3.1.1 Process Description

4.3.1.1.1 System. LEA operation is achieved by reducing combustion air flow to the windbox serving conventional burners. Air flow control to the windbox of gas- and oil-fired firetube and packaged watertube boilers is accomplished by closing the inlet vanes of constant speed forced draft fans or by closing the vanes at the windbox inlet (if these are provided), or both. Figure 4.3-1 illustrates the location of the fan and windbox inlet vanes on two typical arrangements of single-burner packaged boilers. In larger gas- and oil-fired industrial boilers equipped with variable speed induced and forced draft fans, the speed of both fans is controlled to vary the airflow while maintaining the design pressure in the furnace.[97] Since pulverized-coal and large gas- and oil-fired boilers are generally multiburner units, combustion air control requires a compartmented windbox, and the desired excess air level is obtained by altering the speed of the fans. For stoker coal-fired boilers, LEA operation can be achieved by reducing the undergrate air flow. This is accomplished by adjusting the air vanes and the speed of the fans.[101]

4.3.1.1.2 Development status. Low excess air controls are currently being applied to many types of boilers to improve thermal efficiency and reduce fuel costs.


FAN
MOTOR
FAN INLET VALVE
CONTROL LINKAGE
BURNER
COMBUSTION AIR ADJUSTMENT ASSEMBLY

(A) CONTROLLING AIR FLOW TO THE BURNER WITH FORCED DRAFT FAN INLET VANES


WINDBOX INLET VANES
BURNER
FAN/MOTOR ASSEMBLY
CONTROL LINKAGE
COMBUSTION AIR ADJUSTMENT ASSEMBLY

(B) CONTROLLING AIR FLOW TO THE BURNER WITH WINDBOX INLET VANES

Figure 4.3-1. Schematics of two single burner units for packaged boilers showing location and control of combustion airflow vanes.

Recently, manufacturers have been marketing oil- and gas-fired burners designed specifically for LEA firing. These are termed LEA burners (distinct from the low NO_x burners discussed in subsection 4.3.4). These burners can safely support complete combustion at oxygen levels lower than those of conventional burners.[98] These burners are already being installed on new industrial boilers, primarily to improve boiler thermal efficiency in light of escalating fuel costs.[98]

4.3.1.1.3 Applicability to industrial boilers. Low excess air techniques are applicable to all industrial boiler types and fuels. In all cases, an oxygen trim system is recommended to ensure safe, efficient, continuous operation of the boiler with no smoke.[101] Commercially available oxygen trim systems permit automatic LEA operation throughout the boiler's load range. Excess air in the boiler is measured by the excess oxygen concentration in the flue gas. A discussion of the relationship between excess air and excess O_2 is presented in Reference 102 (p.6-9). The oxygen trim system, which consists of in-stack O_2 and CO monitors that control airflow to the windbox, is currently being used in the field. Proper maintenance of these monitors is important to maintaining good combustion.

For stokers clinker formation is a potential concern during LEA operation. If the undergrate airflow is maintained sufficiently high clinkers should not form on the grate.[103] The use of an oxygen trim systems will help ensure reliable continuous operation at the proper O_2 level.

4.3.1.2 Factors Affecting Performance. For a given set of boiler operating conditions the NO_x reduction performance of LEA depends directly on the excess combustion air setting -- the larger the reduction in excess air, the greater the decrease in NO_x emissions. For coal the reduction of one percentage point in O_2 concentration, from a typical normal operating level of between 5 and 10 percent O_2, represents about a 10 percent reduction in excess combustion air requirements. For oil and gas the one percent drop in O_2 concentration (from a normal operating level baseline of between 4 and 8 percent O_2) represents a 5 percent reduction in excess air requirements.[101]

Long-term emission tests conducted by EPA demonstrate the NO_x reduction performance of LEA. The continuous monitoring data for residual oil and spreader stoker boilers, discussed in Section 4.3.7, show that the partial correlations between NO_x emissions and excess oxygen (that is, the correlations between emissions and excess oxygen with boiler load variations factored out) are statistically significant and positive.

The effectiveness of LEA in reducing NO_x emissions from industrial boilers varies with fuel type and boiler design. Operation at LEA levels is generally more effective in reducing the thermal NO_x component.[104] Since a large part of the total NO_x emissions from coal- and residual oil-fired boilers are due to fuel NO_x formation and since LEA operation primarily impacts thermal NO_x, there is a limit to the degree of total NO_x reduction that can be achieved through LEA on coal- and residual oil-fired boilers. This point is discussed further in Section 4.3.7.

Although it is desirable to reduce combustion air as much as possible for NO_x control purposes and to reduce fuel costs, the excess air level must be maintained above minimum levels to avoid incomplete combustion and corresponding higher emissions of CO, HC, and smoke. The minimum excess air levels achievable without measurable increases in CO, HC, and smoke emissions vary according to the fuel burned, the firing mechanism, and the boiler operating load. Table 4.3-1 presents the excess oxygen levels, based on numerous field tests of existing industrial boilers, that are considered indicative of minimum levels for safe operation at firing rates above 80 percent of rated capacity.[102]

TABLE 4.3-1. SAFE OPERATING LEVELS FOR LEA

Fuel/firing type	Minimum excess O_2 (percent)	Typical normal excess O_2 (percent)
Natural gas	0.5 - 3	4 - 8
Oil	2 - 4	4 - 8
Coal/Pulverized	3 - 6	5 - 9
Coal/Stoker	4 - 8	6 - 11

Also listed for comparison, are typical normal operating excess O_2 levels for industrial boilers. The actual minimum excess O_2 concentration marking the onset of incomplete combustion varies with boiler load, and generally increases as the load is reduced.[97] Fuels with low carbon/hydrogen ratio, such as natural gas, can achieve lower excess air levels than heavy oil and coal before increases in CO and carbon soot formation occur.[105]

Variations in ambient conditions, such as temperature, pressure and moisture, that alter the density of the combustion air affect burner excess air and excess O_2 at a given setting. The forced draft fans introduce a constant volume of air to the furnace, but the mass flow changes according to its density. In the absence of compensating controls, temperature variations of 10K (20°F) would change the O_2 concentration by about one percentage point for gas-, oil- or pulverized coal-fired boilers, which normally operate at about 4 percent excess O_2 (20 percent excess air). The same temperature variation would also change the O_2 concentration by about one percentage point in a stoker boiler which normally operates with about 8 percent excess O_2 (60 percent excess air). These changes in excess O_2 concentration could result in changes in NO_x emissions on the order of about 5 percent for all fuel/boiler types. However, new industrial boilers equipped with flue gas monitors and oxygen trim systems automatically adjust combustion air flow to offset these ambient variations and maintain a constant excess O_2 level in the firebox.[98]

4.3.2 Staged Combustion

A second combustion modification technique applicable to industrial boilers is staged combustion (SC). This technique is often used in combination with LEA firing and involves diverting a fraction of the combustion air from the burner(s) and injecting it into the furnace beyond the burner. Depending on the amount of combustion air that is diverted, the burners can be made to operate near or below stoichiometric conditions. (At stoichiometric conditions, 100 percent of the air theoretically needed for complete combustion is injected through the burner windbox.)

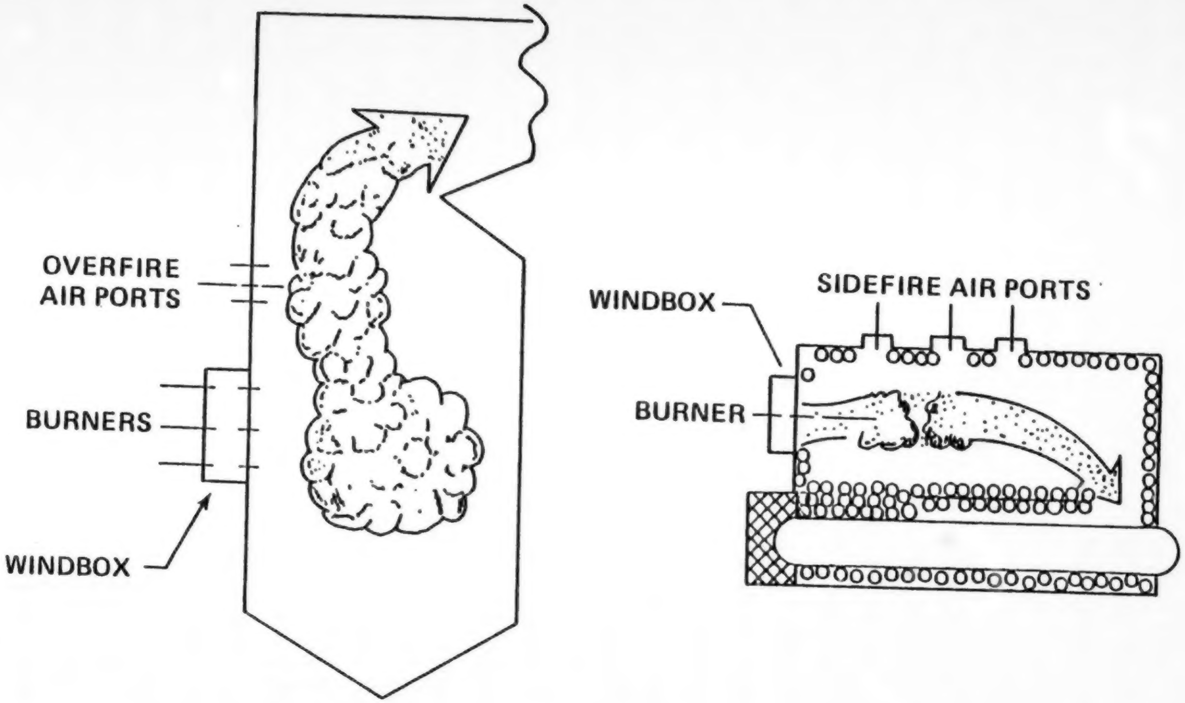
4.3.2.1 Process Description

4.3.2.1.1 System. Like LEA, SC reduces oxygen availability and flame temperatures in the primary combustion zone, resulting in lower thermal and fuel NO_x formation. The additional staged air permits the combustion process to go to completion, oxidizing any unburned fuel and CO formed in the air-deficient combustion zone. The ports used to inject the staged air downstream from the primary combustion zone are normally referred to as overfire air (OFA) ports, sidefire air (SFA) ports, or simply NO_x ports. Depending on the boiler design, either OFA or SFA ports can be used to inject staged air.[98,99] Figure 4.3-2 illustrates schematically the application of OFA for large units and SFA for packaged units. In SC for multiburner units the OFA ports are located above the top burner level. Unlike OFA, SFA is injected from the sides, the top, or the bottom of the furnace. In other respects the two techniques are the same.

Although staged combustion is mainly applicable to boilers with burners (pulverized coal-fired, oil-fired, and gas-fired boilers), staged combustion also occurs in stoker boilers. Stokers generally achieve some degree of staged combustion by their inherent design. Fuel is burned relatively slowly on a grate as compared to the rapid suspension burning which occurs at burners. Staged combustion is also encouraged through the use of OFA ports which are used on most stokers to reduce smoking. OFA tends to reduce undergrate air creating a locally oxygen deficient zone at the fuel bed. Further staging of combustion air with larger fractions of air introduced at the OFA ports has been attempted (see Section 4.3.7.1).

For oil- and gas-fired boilers, a common method of achieving staged combustion is to take one or more burners out of service (BOOS). Burners no longer firing fuel can then be used as OFA or SFA ports. However, many oil- and gas-fired boilers use only a single burner, making BOOS impossible for these units. For single burner units, staged combustion must use separate OFA ports. Many single burner oil- and gas-fired boilers include provisions for OFA or SFA air ports allowing staged combustion controls to be used.

4.3.2.1.2 Development status. The development status of SC for various fuels and equipment types is summarized in Table 4.3-2. SC has been


OVERFIRE AIR PORTS
BURNERS
WINDBOX
WINDBOX
SIDEFIRE AIR PORTS
BURNER

(A) OFA PORTS

(B) SFA PORTS

Figure 4.3-2. Schematic of industrial watertube boilers equipped with (A) OFA ports and (B) SFA ports.

TABLE 4.3-2. DEVELOPMENT STATUS OF STAGED COMBUSTION FOR APPLICATION TO INDUSTRIAL BOILERS

	COAL		OIL AND NATURAL GAS		
Boiler Type	Packaged and field erected stokers	Field erected pulverized	Field erected watertube	Packaged watertube	Packaged firetube
Status	Available but not implemented[a]	Available and implemented	Available and implemented	Available and implemented	Not available R&D status

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[a] Means that the control technique is commercially offered, but is not presently being implemented for emission control.

demonstrated and used commercially on large field-erected pulverized coal-, oil-, and gas-fired industrial boilers. For example, new coal-fired units with heat input capacity greater than 73.3 MW (250 x 10^6 Btu/hr) thermal input sold since 1971 are equipped with OFA injection ports to meet 40 CFR 60 Subpart D New Source Performance Standards for NO_x. In California OFA is used routinely on large residual oil- and gas-fired utility boilers, generally larger than 73.3 MW (250 x 10^6 Btu/hr) thermal input, to meet State and local NO_x regulations for existing units.[106] Since large field-erected industrial boilers are very similar in design and operation to utility units, they exhibit similar NO_x emission levels and are amenable to the same control techniques.[107] OFA ports are a common design feature of industrial stoker-fed boilers, primarily to complete combustion and control smoke. Staged combustion has also been being used on new and existing oil- and gas-fired steam generators in the California oil-fields.[108]

4.3.2.1.3 Applicability to industrial boilers. SC is applicable for all fuel types but not to all existing boiler types. Increased combustion staging in existing stokers has been attempted in recent field tests to lower NO_x emissions. The technique involved a reduction in undergrate air flow. Although NO_x emissions were reduced in most cases, consistent NO_x reductions were not demonstrated for all stokers with increased combustion staging. In general, OFA ports on existing stokers are neither specifically designed nor positioned for NO_x control.[109]

Automatic controls which maintain prescribed airflows to the OFA ports and individual burners to allow more precise operation are commercially available. For example, automatic control systems have been installed recently on two 190 MW (650 x 10^6 Btu/hr) thermal input pulverized coal-fired industrial boilers.[110]

Potential impacts of OFA for PC boilers include increased smoke and particulate matter emissions. Increased furnace slagging and corrosion can also occur when severe SC conditions are implemented. These impacts can be avoided by proper maintenance of excess air levels and proper distribution of air between burners and OFA ports. The combustion air metering system requires a flue gas monitoring system which includes, as a minimum, continous O_2 and opacity monitors. A compartmented windbox is also required to assure equal distribution of windbox air to each burner. These control features are commercially available and are already being implemented in the field.[110]

With stoker-coal-fired boilers, undergrate air flow needs to be maintained high enough to prevent clinker formation, or the bed needs to be poked periodically to break up any forming clinkers. For oil- and gas-fired units, potential problems of smoke and combustible emissions can be avoided by operating the unit with an oxygen trim system, and maintaining a minimum of 3 percent excess oxygen for oil-firing and 2 percent for gas-firing.[102]

4.3.2.2 Factors Affecting Performance. The success of the staged combustion technique depends primarily on the location of the secondary air injection ports and the careful control of the airflow between the OFA or SFA ports and the windbox. Utility boiler experience with staged combustion has shown that ports located too close to the convective section may cause high steam temperatures, incomplete combustion, or both. Conversely, OFA or SFA ports located too close to the burners (or fuel bed in the case of stokers) may decrease the NO_x reduction performance.[111] Manufacturers of large industrial boilers have relied on utility boiler experience to locate OFA or SFA ports to lower NO_x formation without affecting steam temperatures or causing incomplete combustion.[110]

The partitioning of combustion air between the OFA or SFA ports and the windbox, together with the overall excess oxygen level, determine the burner stoichiometry (or undergrate air in the case of stokers). With combustion of coal or heavy fuel oil, operational and safety problems caused by slagging and corrosion can be avoided by maintaining burner air feed rates slightly above stoichiometric conditions (e.g., 5 percent excess air at the burners).[112]

Commercially available airflow controls can be used to maintain the required staged air injection and windbox combustion air flowrates throughout the boiler load range.[112] With distillate oil and gas, burner stoichiometries as low as 90 percent (i.e., combustion air 10 percent below that required for complete combustion) are often possible, but careful control of the operating parameters is required to avoid losses in boiler efficiency.[112]

4.3.3 Flue Gas Recirculation

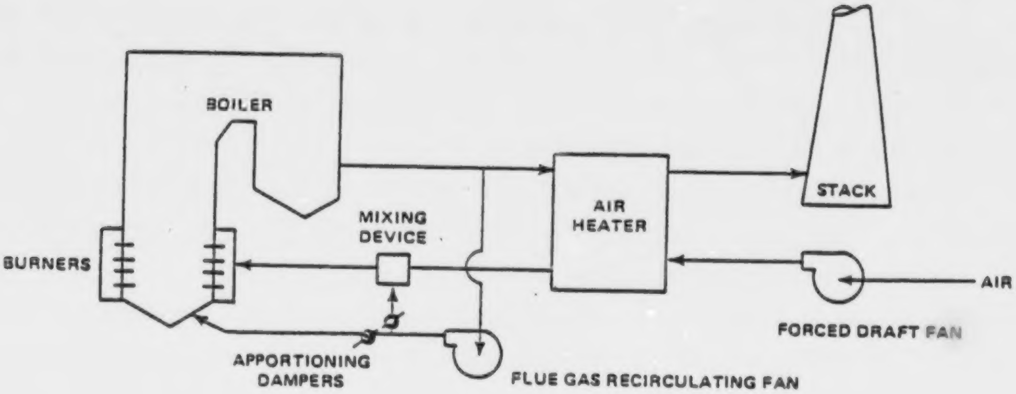
A third technique for NO_x control by combustion modification is flue gas recirculation (FGR). This technique involves extracting a portion of the flue gas and returning it to the furnace through the burner windbox.

4.3.3.1 Process Description

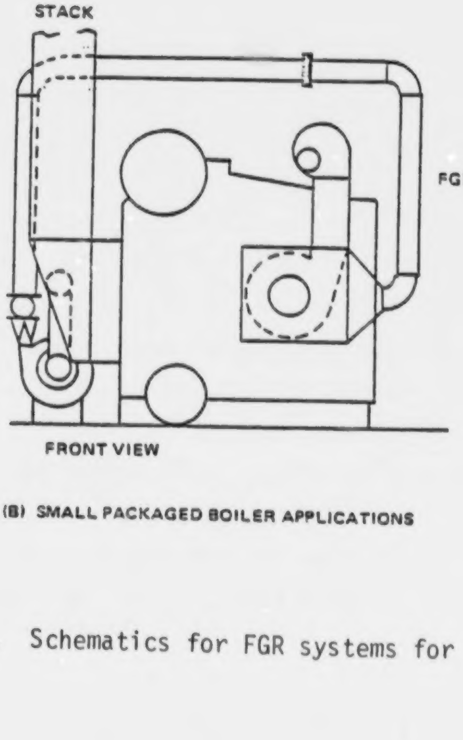
4.3.3.1.1 System. Figure 4.3-3 shows schematics of FGR installations on both a large and a small packaged industrial boiler. The systems consist primarily of an FGR fan assembly, an apportioning and mixing system, and associated ducting connecting the stack (or flue gas duct) to the windbox. The forced draft fan has to be larger when FGR is used than without recirculation to overcome the increase in pressure drop caused by the recirculation of flue gas through the burners. The recirculated flue gas absorbs some of the heat released during combustion. This lowers the bulk furnace gas temperature, resulting in a reduction of thermal NO_x formation. Furthermore, the addition of flue gas reduces the oxygen concentration in the combustion air. The effect is to reduce NO_x formation by decreasing the oxygen available to react with the nitrogen.[114]

4.3.3.1.2 Development status. FGR is commercially available and applicable to all gas- and distillate oil-fired industrial boiler types. For example, in 1978, FGR was installed on two new 15 MW (50 x 10^6 Btu/hr) thermal input packaged watertube gas/oil-fired boilers which are now in operation in Southern California.[115]

FGR is not, however, as effective for residual oil- and coal-fired boilers.[115] When these fuels are burned, as much as 40 to 60 percent of the total NO_x emissions may be attributed to formation of NO_x from fuel-bound nitrogen. Limited test data have shown that recirculation rates of up to 15 percent decreased NO_x emissions by 17 percent when firing high nitrogen fuels whereas a similar recirculation rate decreased NO_x by as much as 50 percent for gas and distillate oil-fired boilers with no air preheat.[107,111,116]


BOILER
STACK
MIXING DEVICE
AIR HEATER
BURNERS
AIR
FORCED DRAFT FAN
APPORTIONING DAMPERS
FLUE GAS RECIRCULATING FAN

(A) LARGE INDUSTRIAL BOILER APPLICATIONS


STACK
FGR DUCTS
FRONT VIEW

(B) SMALL PACKAGED BOILER APPLICATIONS

Figure 4.3-3. Schematics for FGR systems for industrial boilers.[113]

4.3.3.1.3 Applicability to industrial boilers. Implementation of FGR for NO_x control requires extra fan capacity and ducting. Fans are reported to erode rapidly at the high operating temperatures encountered which may increase safety hazards and operating problems.

By designing the burner and windbox to account for the increased gas flow, and by maintaining maximum FGR rates at a safe 20 to 25 percent flame stability can be maintained. Some burner designs are capable of withstanding slightly higher FGR rates without incurring flame instabilities.[111,116] Flame sensors should be located and their sensitivity adjusted to detect the onset of combustion instability.

4.3.3.2 Factors Affecting Performance. The recirculation rate is the only FGR operating parameter that can be varied to control NO_x reductions, and, as shown in Figure 4.3-4, NO_x emissions decrease as the recirculation rate is increased. It is important to note that these curves indicate percentage reductions in emissions rather than absolute reductions (ng/J or $lb/10^6$ Btu). Thus the absolute emission reduction may actually be higher for the residual oil-fired boiler compared to the natural gas-fired boiler due to different uncontrolled emissions. The potential for flame instability at high FGR rates generally limits recirculation to 25 to 30 percent.[106,111]

4.3.4 Low NO_x Burners

4.3.4.1 Process Description. New burner designs are being developed for industrial boilers which alter the mixing of air, fuel, and combustion products within the burner flame zone to reduce NO_x formation. Lower NO_x emissions are obtained by peak flame temperature reduction, staging, and local combustion product recirculation. For example, commercially available LNB's for coal-fired utility boilers use delayed fuel/air mixing and low turbulent flames to produce a staging effect. The oil-fired LNB's that are currently being developed may use a combination of cooling and staging. Flame surface area is increased for greater heat dissipation. Local gas recirculation is promoted to cause rapid quenching of the flame and cool the

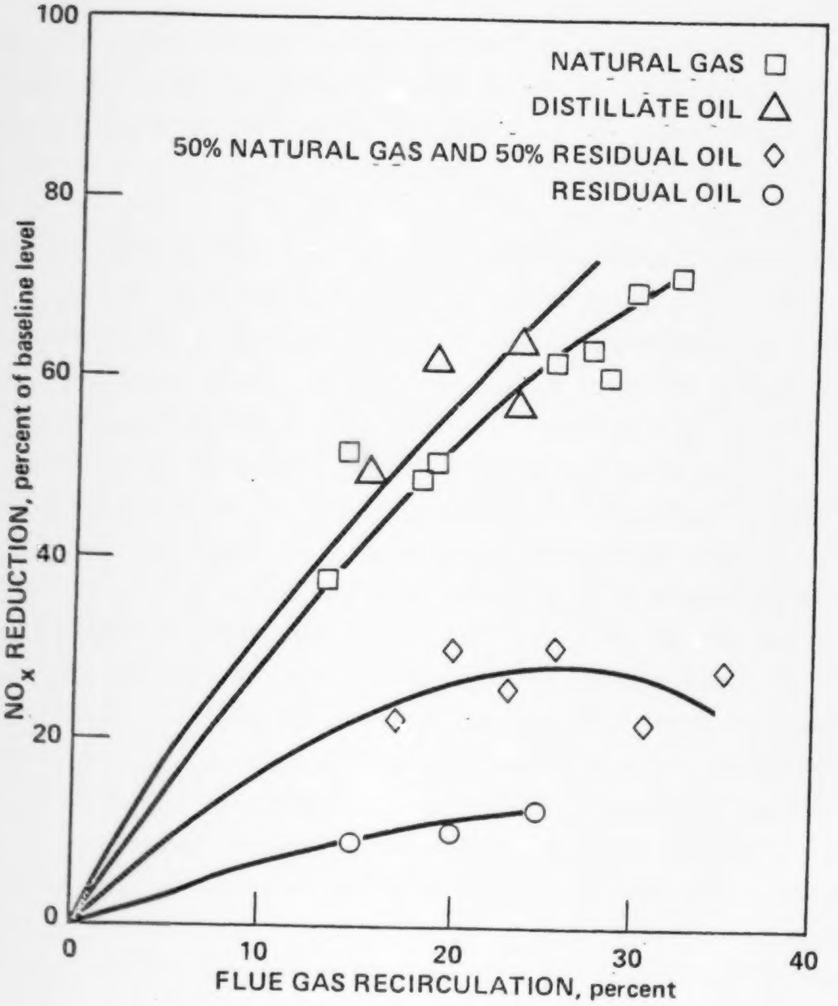


Figure 4.3-4 . FGR test results on a 5.1 MW (17.5 x 10^6 Btu/hr) packaged watertube boiler. 106 (No air preheat)

combustion process, and controlled air/fuel mixing is used to provide staging.[118]

Low NO_x burners have been classified by a variety of schemes. For purposes of this evaluation, a low NO_x burner is considered to be any burner that internally achieves either of the following NO_x reduction techniques:

- Staged combustion (distributed mixing, multiple stage combustion, or off stoichiometric combustion)
- Self-recirculation

Burners designed to operate under LEA conditions but which do not incorporate either of the above techniques are not considered low NO_x burners.

In general, commercial demonstration experience with low NO_x burners applied to industrial boilers is very limited. Field testing of small boilers (3 MW or 10 x 10^6 Btu/hr) firing gas and oil has occurred[119] and low NO_x burners (self-recirculation type) are currently in use at three 15 MW (50 x 10^6 Btu/hr) boilers.[233] However, several vendors are offering low NO_x burners for certain applications, and widespread commercial utilization of this technology could occur with the next few years.

The major factor inhibiting widespread application of low NO_x burners to industrial boilers appears to be burner size. Use of low NO_x burners on process heaters, where burner size is generally smaller than 5.9 MW (20 x 10^6 Btu/hr), is widespread. Industrial boilers, on the other hand, may use burners as large as 73 MW (250 x 10^6 Btu/hr).[120] There is no technical constraint to using multiple small low NO_x burners on large industrial boilers, however, the cost of the multiple burner boiler may be higher than an equivalent single burner boiler. This cost difference is partly due to the current trend in which single burner boilers can be shop-erected rather than field-erected.

4.3.4.2 Factors Affecting Performance. Preliminary results suggest that NO_x emissions increase from gas/oil-fired LNB as oil temperature is raised.[121] No final assessment has been made of this effect nor of attempts to resolve it. Since some LNB designs under development may lead to extended flame zones, it may be necessary to use an enlarged firebox to avoid flame impingement on the back wall of the boiler. However, the need for an enlarged firebox is not clear at this time.[112,118]

4.3.5 No Combustion Air Preheat or Reduced Air Preheat

4.3.5.1 Process Description. Using combustion air at ambient temperatures instead of preheating it results in a lower peak temperature in the primary combustion zone. This in turn lowers thermal NO_x production. Most industrial watertube boilers with design heat input capacities greater than 15 MW (50 x 10^6 Btu/hr) recover some flue gas heat in combustion air preheaters or feedwater economizers to maximize thermal efficiency.[106] The installation of an economizer instead of a combustion air preheater on new boilers will result in lowered peak temperatures while still allowing for effective flue gas heat recovery.[123] Lowering peak temperatures is primarily effective for reducing thermal NO_x, but has little effect on fuel NO_x. Hence, the technique of no combustion air preheat will result in higher percent reductions for low nitrogen fuels -- distillate oil and natural gas.[122]

4.3.5.2 Factors Affecting Performance. The only factor affecting the NO_x reductions achievable by reducing combustion air preheat is the degree of air preheat reduction. Limited testing on distillate oil- and natural gas-fired boilers has indicated that the reduction of combustion air preheat is effective in reducing NO_x emissions over a wide range of combustion air temperatures -- 300 to 500K (80° to 440°F).[106] RAP is not as effective on residual oil- and coal-fired industrial boilers due to the fuel nitrogen contribution to the total NO_x emissions and the ineffectiveness of RAP in reducing fuel NO_x emissions. The effectiveness of reducing NO_x emissions by using an economizer instead of an air preheater can be seen in the difference in NO_x emissions between boilers with and without air preheat. (See Sections 4.3.7.3 and 4.3.7.4).

4.3.6 Ammonia Injection

4.3.6.1 Process Description. Ammonia (NH_3) injection involves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using ammonia as the reducing agent. This technique is often referred to as selective noncatalytic reduction or thermal DeNO$_x$. At a molar ratio of 1.5 moles NH$_3$ per mole NO$_x$, over 40 percent of the NO can be reduced if the reaction is designed to take place at a location in the boiler where the temperature ranges from 1200 to 1260 K (approximately 1700° to 1800°F) Outside the range of 1175 to 1350 K (approximately 1650° to 2000°F) less than 10 percent of the NO$_x$ in the flue gas can be reduced to nitrogen and water by ammonia injection.[124] Since ammonia must be injected into the section of the boiler that is within the narrow optimal temperature window, some curtailment of load following capability may result. Investigations with multiple NH$_3$ injection ports are under way to seek a resolution of this problem. H$_2$ injection with the NH$_3$ can also be used to increase the temperature range over which the process is effective.[125]

Sulfur-containing fuels present another potential problem. The formation of ammonium sulfate or ammonium bisulfate can cause plugging of an air preheater or corrosion of boiler parts. Increased frequency of water washing will minimize this problem.[124] To insure that ammonia emissions to the atmosphere are minimized, ammonia sensors and feedback control systems for the injectors may be required.

Ammonia injection is applicable to all industrial boiler types and fuels where there is access in the proper temperature range. Although this technique is commercially offered, it is not currently applied to any domestic operating industrial boiler.[124] Ammonia injection has been installed on three gas- and oil-fired boilers ranging in size from about 16 to 79 MW (55 to 270 x 10^6 Btu/hr) thermal input in Japan.[126] In the U.S. this technique has been investigated only on pilot-scale facilities, except for one commercial installation on a crude oil-fired thermal enhanced oil recovery steam generator.[127] This installation is not currently operating because of problems experienced with the steam generator. Ammonia injection is scheduled for application on large residual oil-fired utility boilers in Southern California by 1982.

4.3.6.2 Factors Affecting Performance. The required reaction temperatures for noncatalytic decomposition of NO with ammonia are found in different areas of the boiler depending on its design and operating load.

For example, at full load these temperatures occur in the convective section of both packaged and field-erected watertube boilers. Changing boiler load, however, causes a shift in the temperature profile through the boiler, reducing NO_x removal to below 30 percent. For small firetube boilers, optimal ammonia injection temperatures occur directly in the firebox. In this area of the boiler, cross-sectional flue gas temperatures are often not uniform, causing significant degradation of the NO_x reduction performance to below 10 percent.[124]

For new units, multiple ammonia injection grids can be strategically designed and located to compensate for temperature gradients and shifts in temperature profiles with changing loads. This technique, however, has not yet been demonstrated.[124]

Other factors affecting performance include NH_3 injection rate and residence time at optimal temperature. The optimal NH_3/NO_x molar ratio has been established to be approximately 1.5, with no additional NO reduction gained by increasing the ratio to 2.0. Maximization of the residence time at optimal temperature can be achieved by proper location of the multiple injection grids. A cross-sectional temperature profile will be required for each boiler design to identify these locations.[124]

4.3.7 NO_x Emission Reduction Data

This section presents available NO_x emission data for combustion modifications in coal-, oil-, and natural gas-fired industrial boilers. The data are presented by fuel type, boiler type, and combustion modification technique used. All data were collected using EPA approved methods as specified in 40 CFR 60, Appendix A.

Each subsection contains both continuous monitoring data and "short-term" data. The continuous monitoring data were obtained on specific units during test periods ranging from 17 days to 24 months. The short-term data, however, were collected during 30-minute to 2-hour test periods at a large number of industrial boiler sites. Considerable variation is evident in the short-term data due to variations in fuel nitrogen contents, boiler heat release rates, burner designs, and combustion air temperatures between boilers. Thus, the short-term data is used primarily to illustrate trends, whereas the continuous monitoring is more representative of the NO_x emission levels that can be achieved for a specific boiler/fuel combination over a range of operating conditions.

Appendix C contains a more detailed listing of short-term data used to construct plots presented in this section. All the short-term data were taken from Reference 128. Appendix C also contains hourly and daily emission data and more information on each of the continuous monitoring tests.

4.3.7.1 Coal-Fired Boilers. NO_x combustion modification data for coal-fired boilers are presented according to boiler type (i.e., pulverized, spreader stoker, and other stokers) and combustion modification technique. The combustion modification techniques for which coal-fired boiler data are available are LEA and staged combustion.

NO_x emissions of two pulverized coal-fired boilers at Location I (1976 start-up) firing low-sulfur coal were monitored continuously for 24 one-month periods. At this installation, two 88 MW (300×10^6 Btu/hr) boilers share a common stack and NO_x monitor. The control techniques used at this installation are excess oxygen control (LEA) and staged combustion (SC) using manually adjustable overfire air compartments. The first six months, which are representative of the test period, are shown in Figures 4.3-5 through 4.3-10. During the entire test period, individual 24-hour averages ranged from 108 to 344 ng/J (0.25 to 0.8 lb/10^6 Btu); however, all but one of the monthly averages were at or slightly below 258 ng/J (0.6 lb/10^6 Btu). During the test period, one boiler had an average load of 71 percent of capacity with daily loads ranging from 33 to 94 percent of capacity. The second boiler, discounting one extremely low load day, averaged 57 percent of capacity, with daily fluctuations from 26 to 94 percent of capacity. The vendor NO_x emission guarantee for these boilers is 301 ng/J (0.7 lb/10^6 Btu) heat input when burning coal. A typical coal analysis indicated a nitrogen content of about 1.6 percent and a heat content of (14,000 Btu/lb) on a dry basis.

In a 1977 study, the presence of oxygen in the coal fuel was hypothesized as a contributer to increased NO_x emissions in tangentially

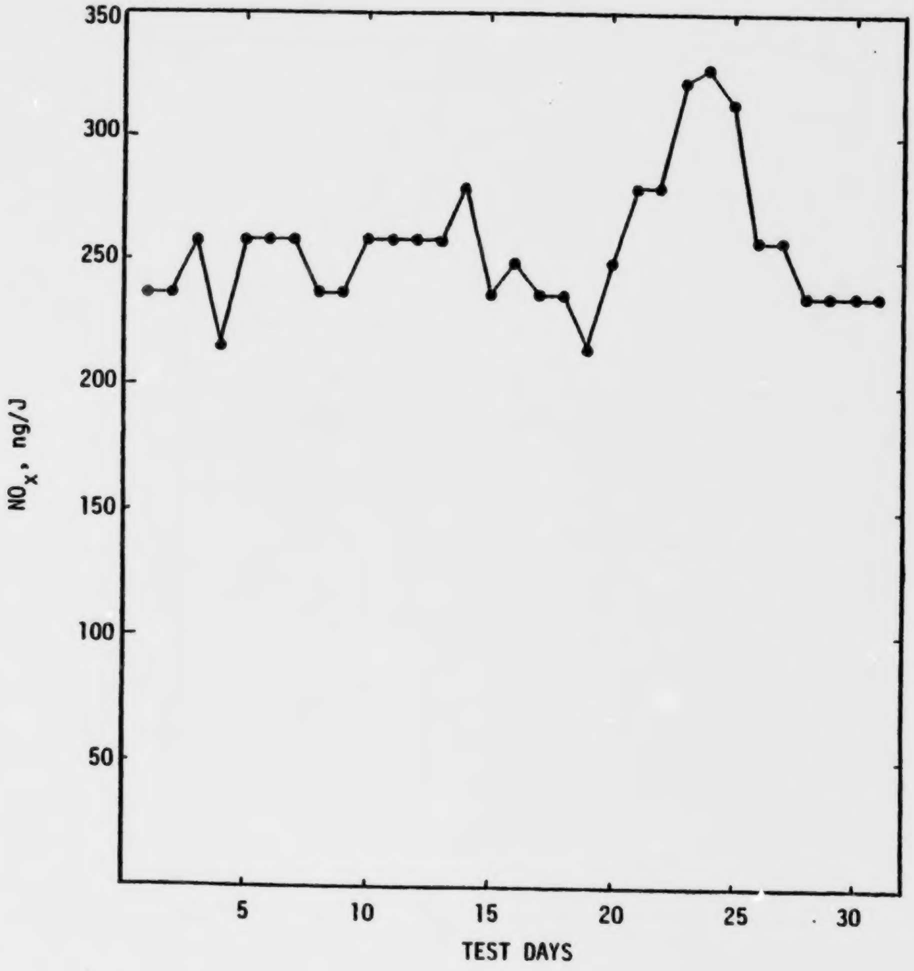


Figure 4.3-5 Continuous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #1).

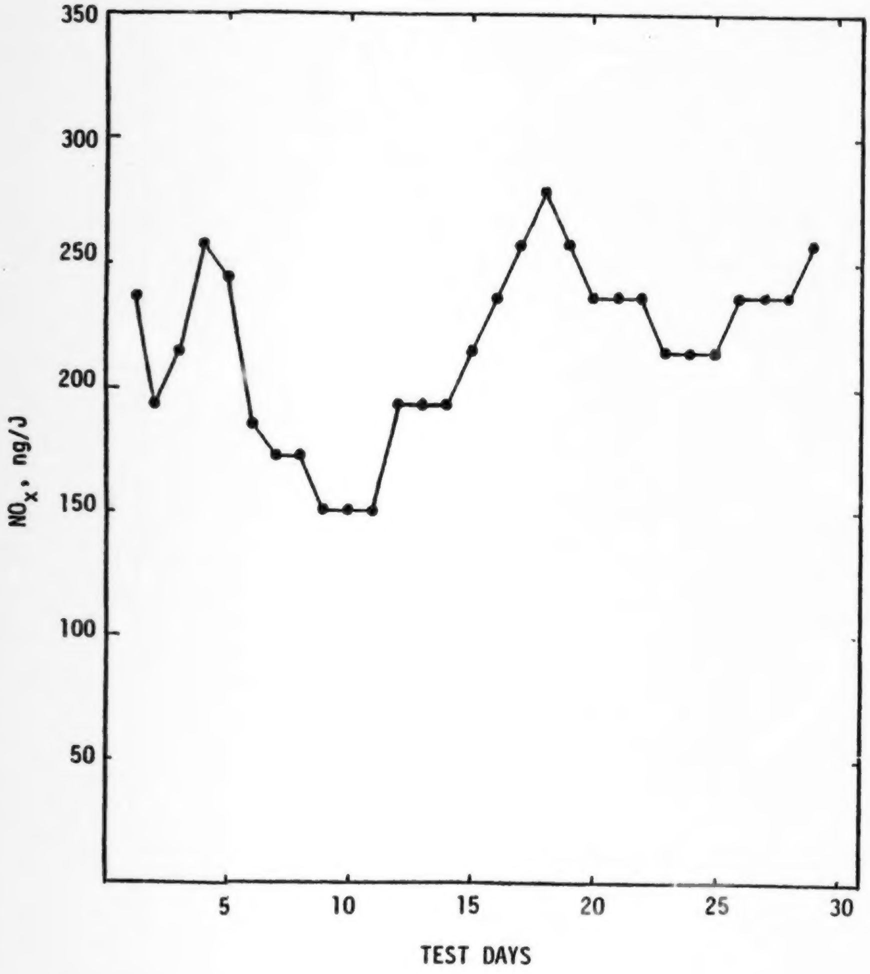


Figure 4.3-6. Continuous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #2).

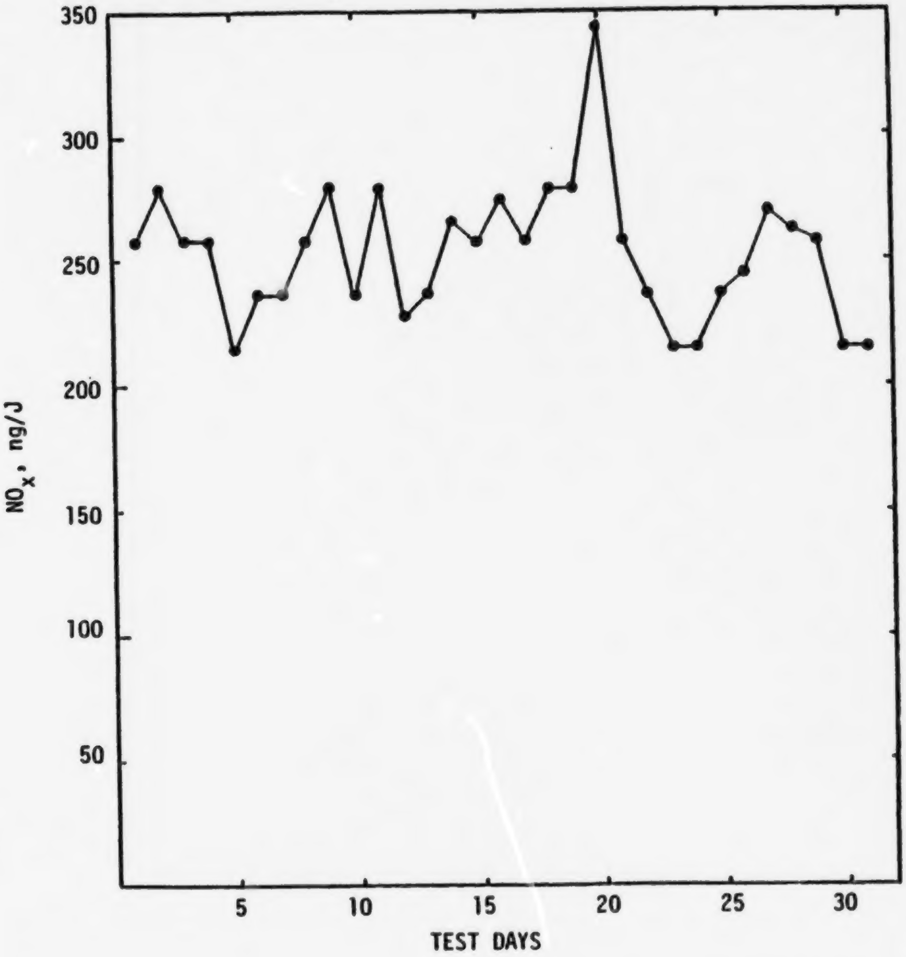


Figure 4.3-7. **Continuous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #3).**

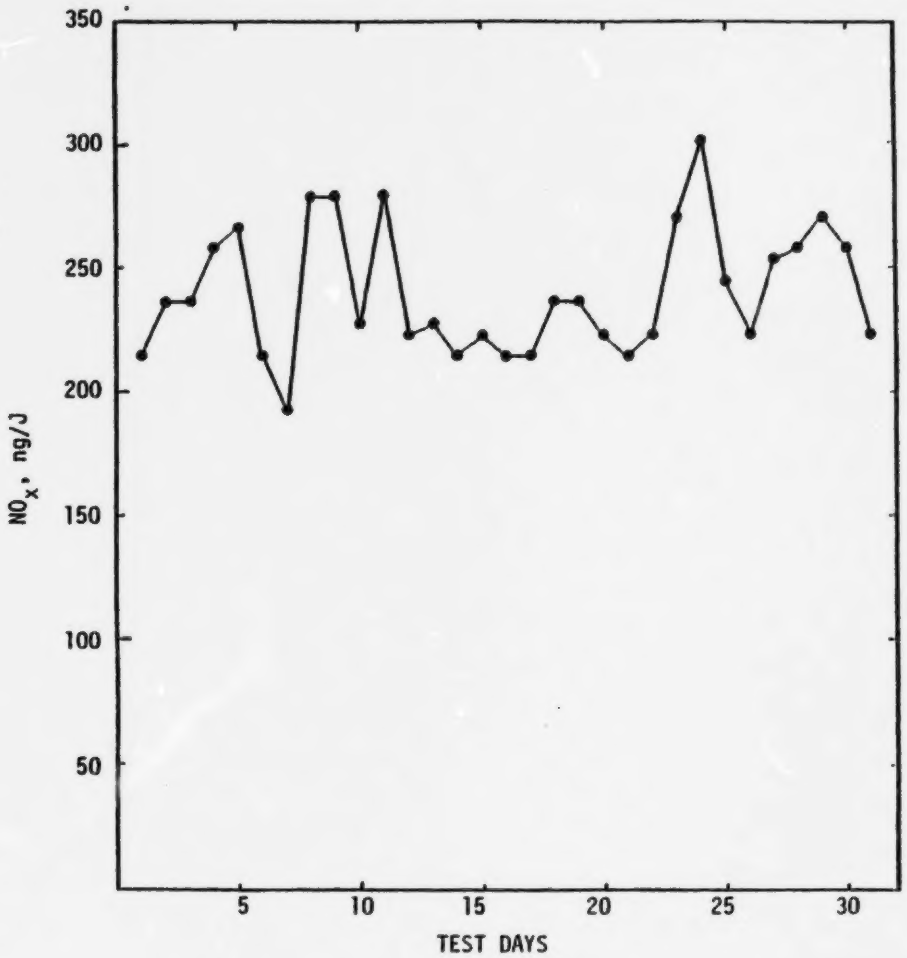


Figure 4.3-8. **Continous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #4).**

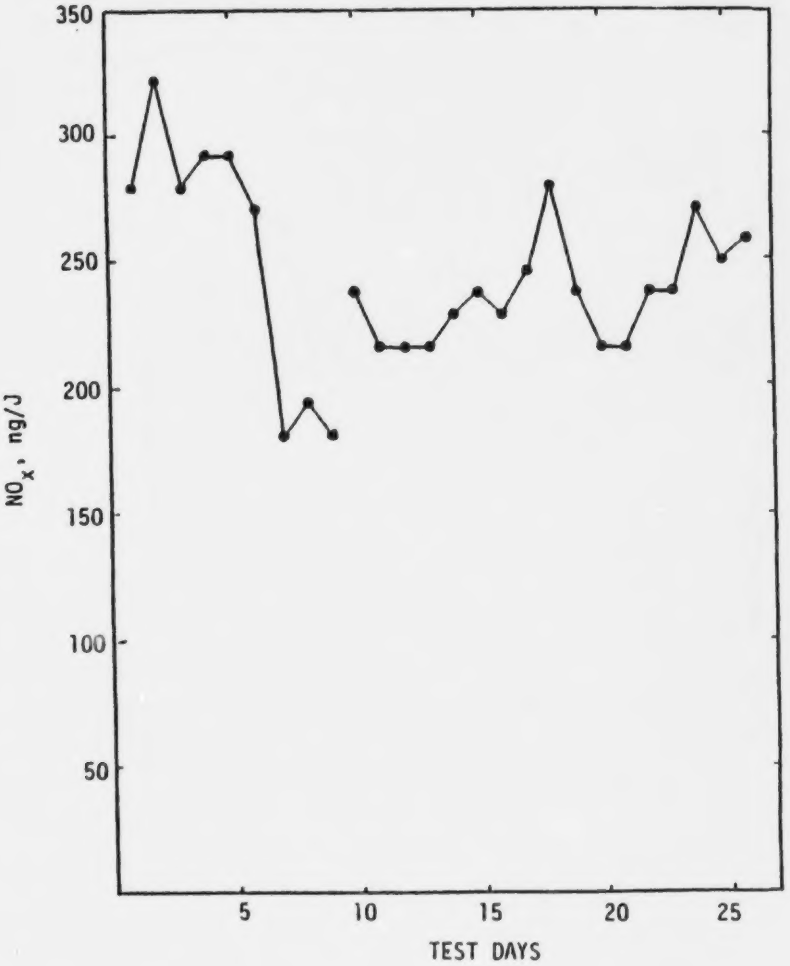


Figure 4.3-9. Continuous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #5).

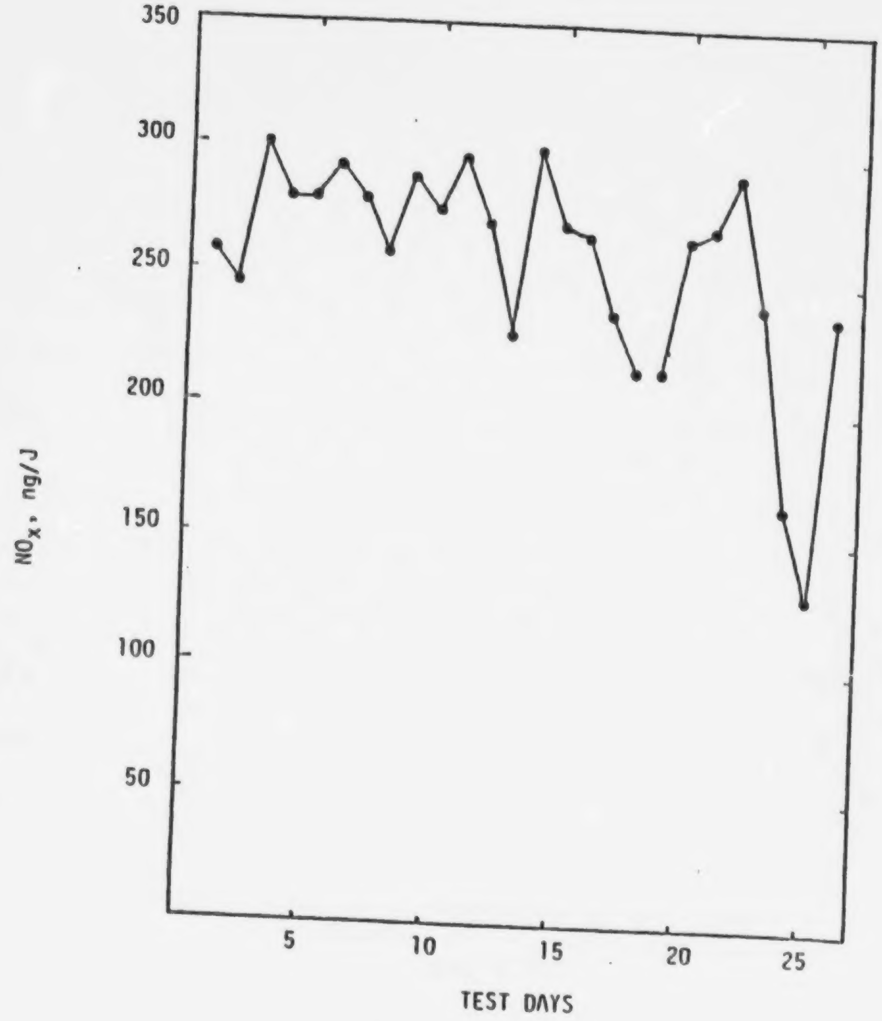


Figure 4.3-10. Continuous monitoring data for LEA/OFA combustion modification on a pulverized coal-fired boiler (month #6).

fired pulverized coal boilers.[129] Figure 4.3-11 presents the results of this study. This figure predicts the fuel NO_x fraction of NO_x emissions as a function of coal nitrogen content and coal oxygen/coal nitrogen ratio. This study indicates that western sub-bituminous coal may actually result in slightly higher NO_x emissions despite the lower fuel nitrogen content due to the higher coal oxygen/coal nitrogen ratio. However, data presented on coal properties indicates that coals with high coal oxygen/coal nitrogen ratios tend to have lower coal nitrogen contents. Thus, the two influences tend to balance one another resulting in reasonably similar fuel NO_x emissions for a variety of coal types.

As stated earlier, staged combustion is effective in reducing fuel NO_x emissions since it reduces the available oxygen in the flame zone. The four major pulverized coal-fired boiler manufacturers (C-E, Babcock and Wilcox, Foster Wheeler, and Riley Stoker) now produce new boilers equipped with overfire air provisions (staged combustion) that are guaranteed to emit NO_x equal to or less than the 1971 NSPS of 301 ng/J (0.7 lb $NO_x/10^6$ Btu).[130]

Spreader Stoker Boilers

Continuous NO_x emission monitoring was conducted by EPA on two spreader stoker boilers equipped with low excess air controls. These data, including daily average NO_x emissions, percent O_2 in the flue gas, and boiler load are shown in Figures 4.3-12 and 4.3-13.

The boiler at Location II (Figure 4.3-12) is a spreader stoker with a rated steam capacity of 45,400 kg/hr (100,000 lb/hr) which fires a high sulfur coal. Coal analyses showed an average nitrogen content of 1.3 percent nitrogen and a heating value of 27,940 kJ/kg (12000 Btu/lb). Daily average NO_x emissions ranged between 154 and 189 ng/J (0.36 to 0.44 lb/10^6 Btu), averaging 170 ng/J (0.40 lb/10^6 Btu) for the 30-day test period. During the first 20 test days, Figure 4.3-12 shows NO_x emissions decreasing as excess O_2 is decreased at relatively constant boiler load. Test days 27 through 30 show that NO_x emissions did not increase significantly during lower load operation despite increases in excess air levels.

Other results of EPA testing at Location II showed that LEA operation resulted in a 24 percent decrease in particulate emissions measured at the

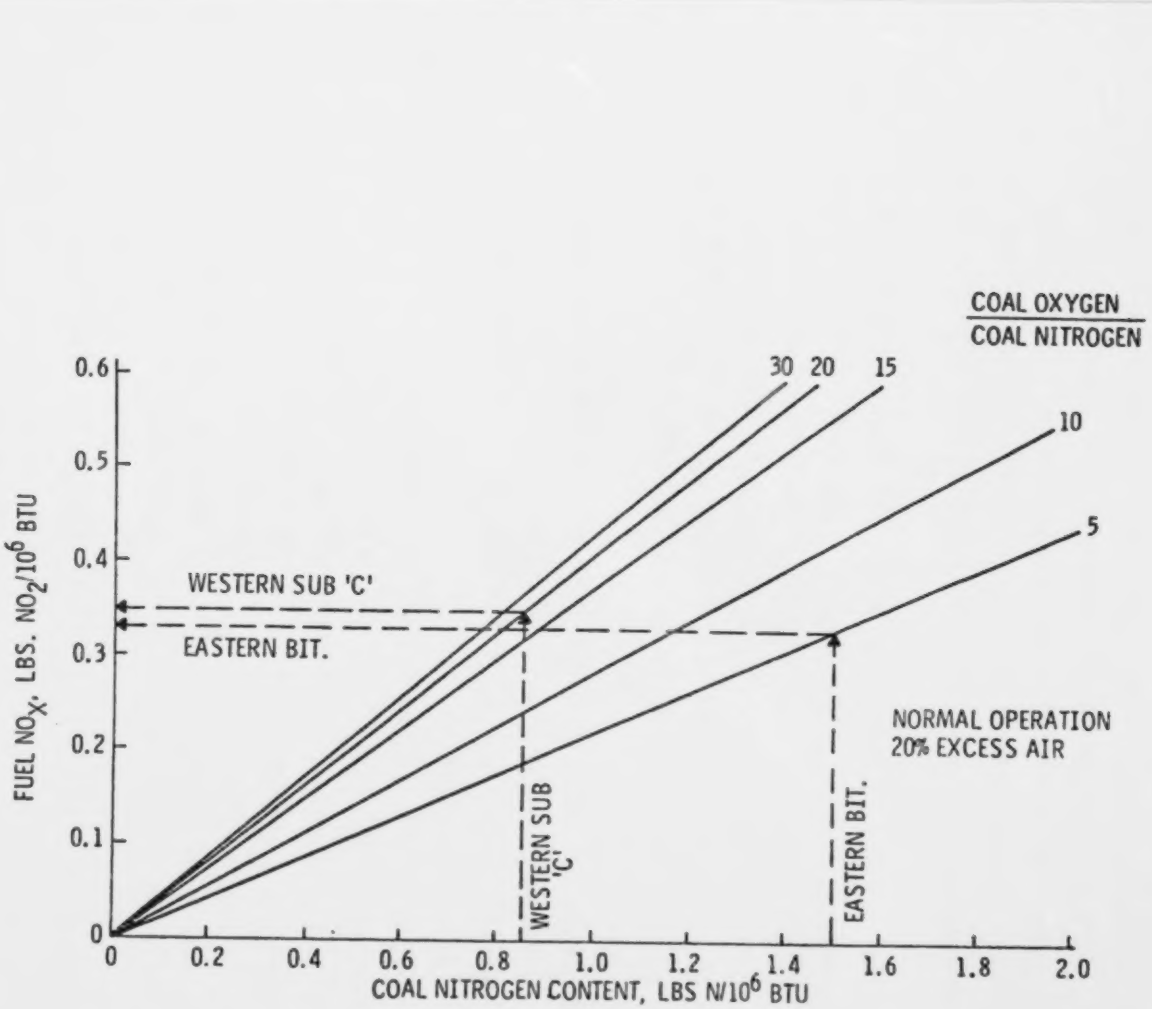


Figure 4.3-11 Fuel NO_x formation as a function of the coal oxygen to nitrogen ratio and the coal nitrogen content.

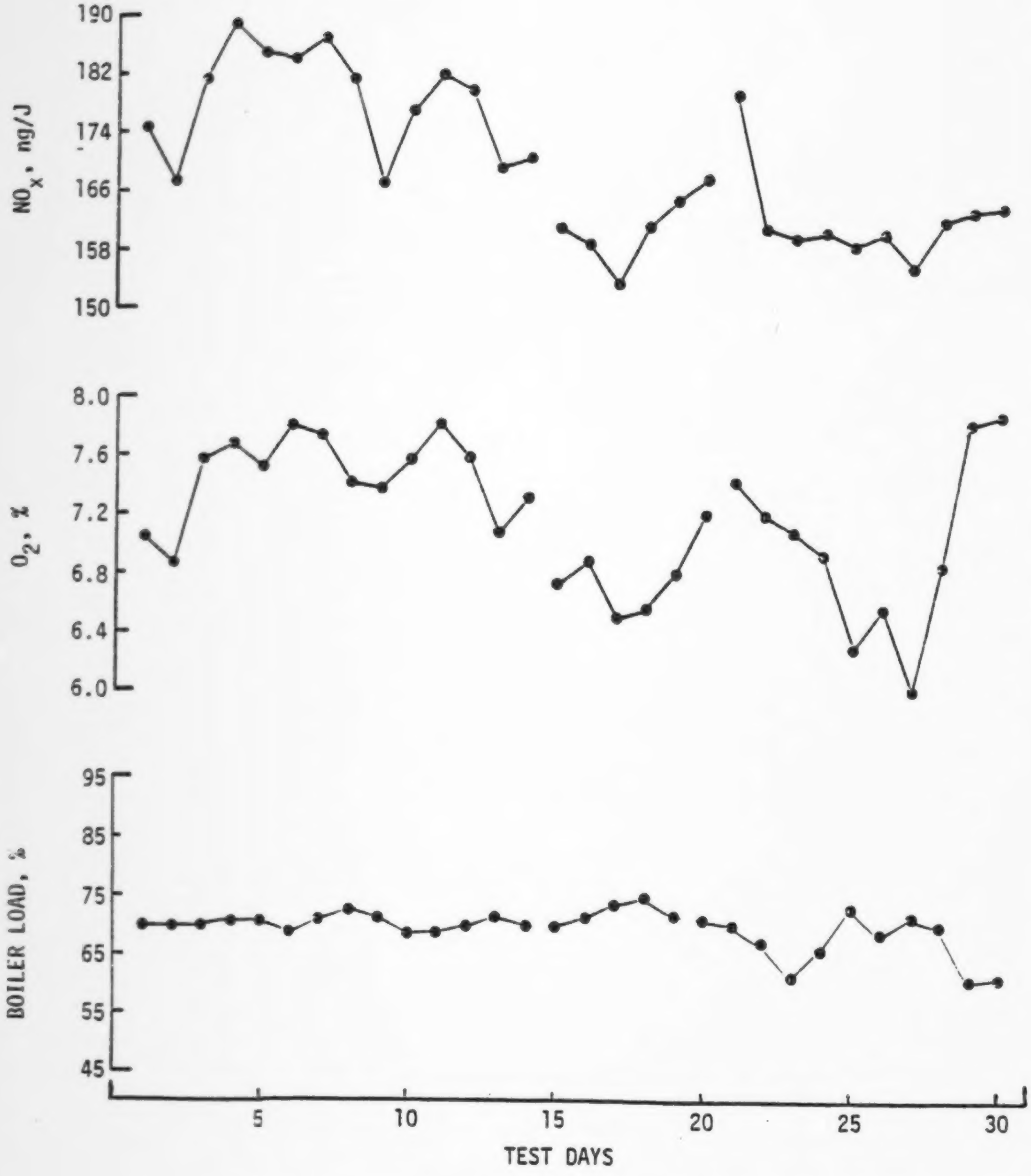


Figure 4.3-12. Continuous monitoring data for LEA combustion modification on a spreader stoker coal-fired boiler at Location II.

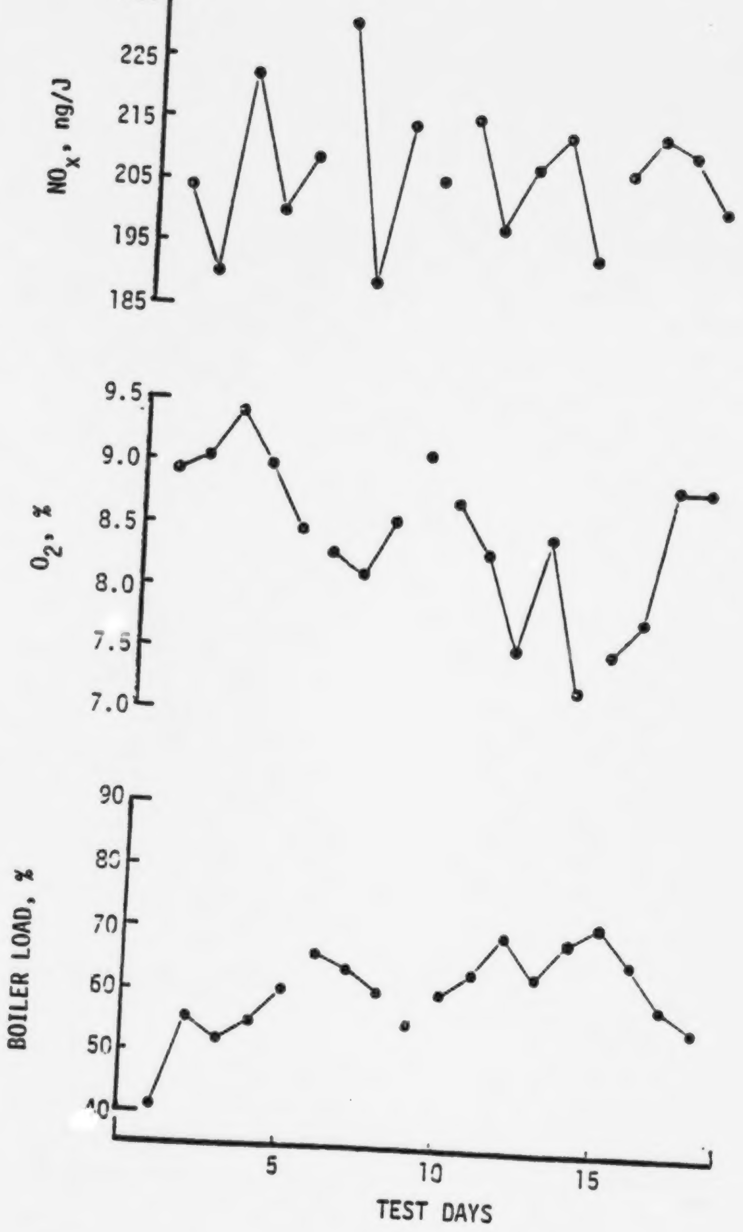
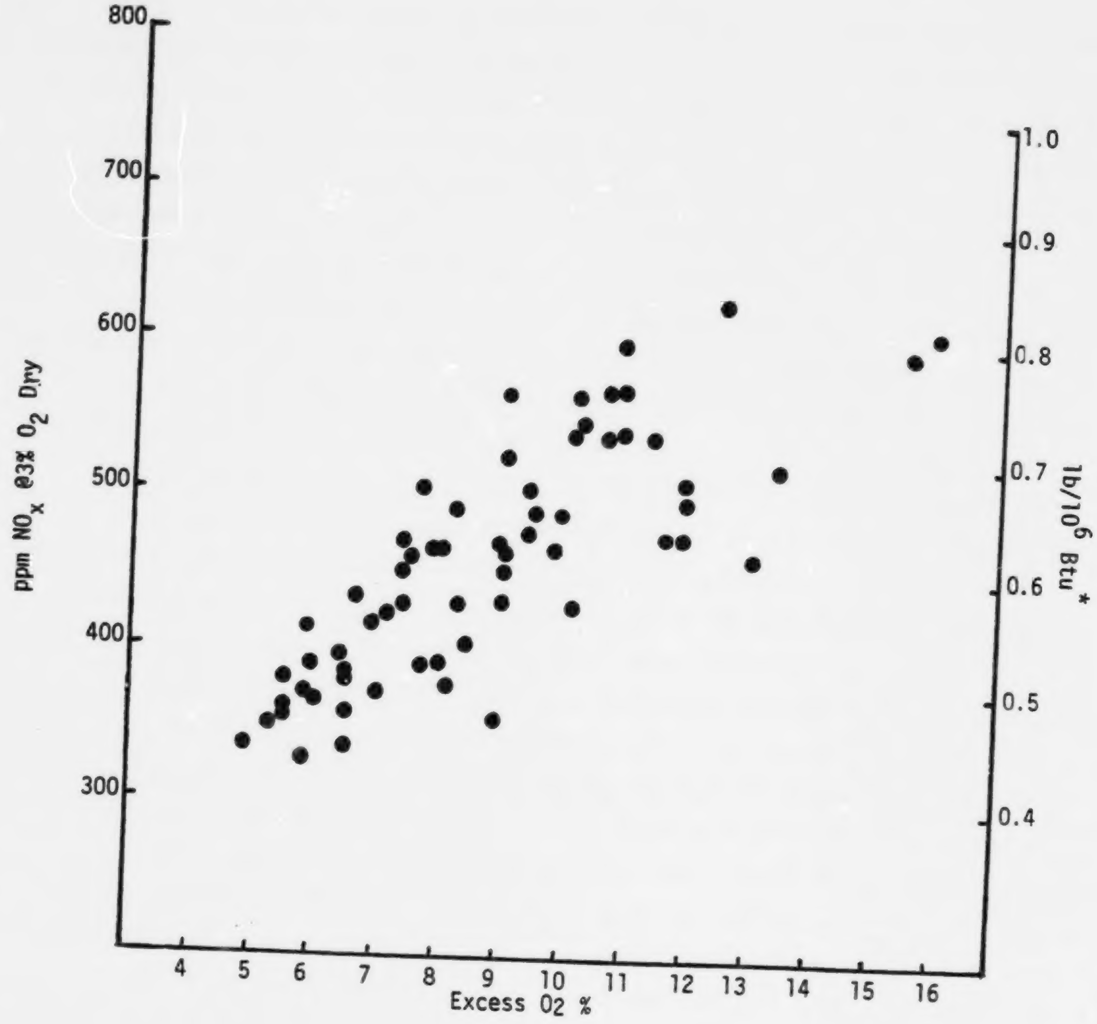


Figure 4.3-13. Continuous monitoring data (8-hour average) for LEA combustion modification on a spreader stoker coal-fired boiler at Location III.

outlet of the mechanical collector relative to normal operation. Other observations during LEA operation relative to normal operation included: no effects on plume opacity (constant at 10 percent), no discernable effect on polycyclic organic matter emissions (POMs), and little effect on boiler efficiency or carbon monoxide emissions. (See Appendix C for reference).

At Location III (Figure 4.3-13), LEA conditions were maintained only while the test contractor was onsite, i.e., eight hours per day, five days per week. Thus, the data plotted in Figure 4.3-14 represent averages of the eight hour period when LEA conditions were maintained. NO_x emissions during LEA operation averaged 208 ng/J (0.48 $lb/10^6$ Btu) ranging from 190 to 231 ng/J (0.44 to 0.54 $lb/10^6$ Btu). During the test period, hourly boiler loads ranged from 37 to 76 percent of capacity, with an average load of 60 percent. Other effects of LEA operation included a decrease of 23 percent (614 ng/J down to 474 ng/J) in particulate emissions, a reduction in percent opacity from 35 to 25 percent, an increase of approximately 0.5 percent in boiler efficiency, and no observable effect on polycyclic organic matter or carbon monoxide emissions. (See Appendix C for reference). For these tests the spreader stoker boiler rated at 72,600 kg/hr (160,000 lb/hr) steam output was firing a coal of about 0.8 percent nitrogen with a heat content of 14790 kJ/kg (8500 Btu/lb).

Figure 4.3-14 shows short-term NO_x emissions data from several different spreader stoker boilers as a function of excess oxygen. These data were collected on four spreader stoker boilers ranging in size from 22,500-91,000 kg/hr (50,000-200,000 lb/hr) of steam capacity at loads between 35 and 100 percent. The data in Figure 4.3-14 clearly show that NO_x emissions tend to decrease as excess oxygen is reduced. Scatter in the test data may be attributed to the fact that fuel characteristics and boiler heat release rate varied between the boilers tested. However, all the data taken at excess O_2 levels of 7 percent or less (50 percent excess air) fall below 256 ng/J (0.60 $lb/10^6$ Btu). Seven percent excess O_2 is typically within the range of safe excess O_2 levels for industrial stoker-fired boilers, as discussed in Section 4.3.1.



*Assuming 0.1 lb/10^6 Btu = 75 ppm NO_x @ 3% O_2 dry.

Figure 4.3-14. NO_x emissions vs. excess O_2 - Short-term data for coal-fired spreader stokers. (unstaged combustion)

Figure 4.3-15 shows short-term data for a 56,750 kg/hr steam (125,000 lb/hr steam) spreader stoker operated under staged combustion conditions. Data taken under normal operating (unstaged) conditions are also shown for comparison. Boiler loads during these tests varied from 40 to 70 percent. This figure shows that staged combustion has little or no effect on NO_x emissions. By virtue of their inherent firing technique, spreader stokers appear to achieve some degree of staged combustion without the use of additional staging air. Volatile matter is driven off the fuel bed as the coal is fed onto the grate creating a fuel rich combustion zone at the grate with lower combustion intensity and relatively slow burning.

Figure 4.3-16 shows short-term data from two mass-fed stoker boilers. One unit of 27,000 kg/hr (60,000 lb/hr) steam capacity fired coal with a relatively low nitrogen content of 0.9 percent; NO_x emissions from this unit were generally lower than those from the second unit of 97,000 kg/hr (215,000 lb/hr) steam capacity which fired coal with a nitrogen content of about 1.4 percent. Both sets of data show uncontrolled NO_x emissions from mass-fed stokers to be lower than those from spreader stokers - less than 215 ng/J (0.5 lb/10^6 Btu) under all conditions. No reduction in emissions was noted during staged combustion tests. Loads during these tests ranged from 25 to 100 percent of rated capacity.

4.3.7.2 Residual Oil-Fired Boilers. Figure 4.3-17 shows the results of continuous NO_x emission monitoring tests conducted at a 35,900 kg steam/hr (79,000 lb steam/hr) residual oil-fired boiler at Location IV. Tests were conducted using low excess air (LEA) and LEA in combination with staged combustion. Staged combustion conditions were simulated by removing one of three burners from service. Controlled NO_x emissions averaged 112 ng/J (0.26 lb/10^6 Btu) for the 29-day test period. Emissions during 16 days of LEA testing averaged 123 ng/J (0.29 lb/10^6 Btu). Average emissions during the remaining 13 days, when staged combustion was used, were 98 ng/J (0.23 lb/10^6 Btu). These data show that staged combustion in combination with LEA achieves greater reduction in NO_x emissions than LEA alone. Other effects noted during LEA/staged combustion operation (relative to unstaged combustion) included an increase in particulate matter emissions

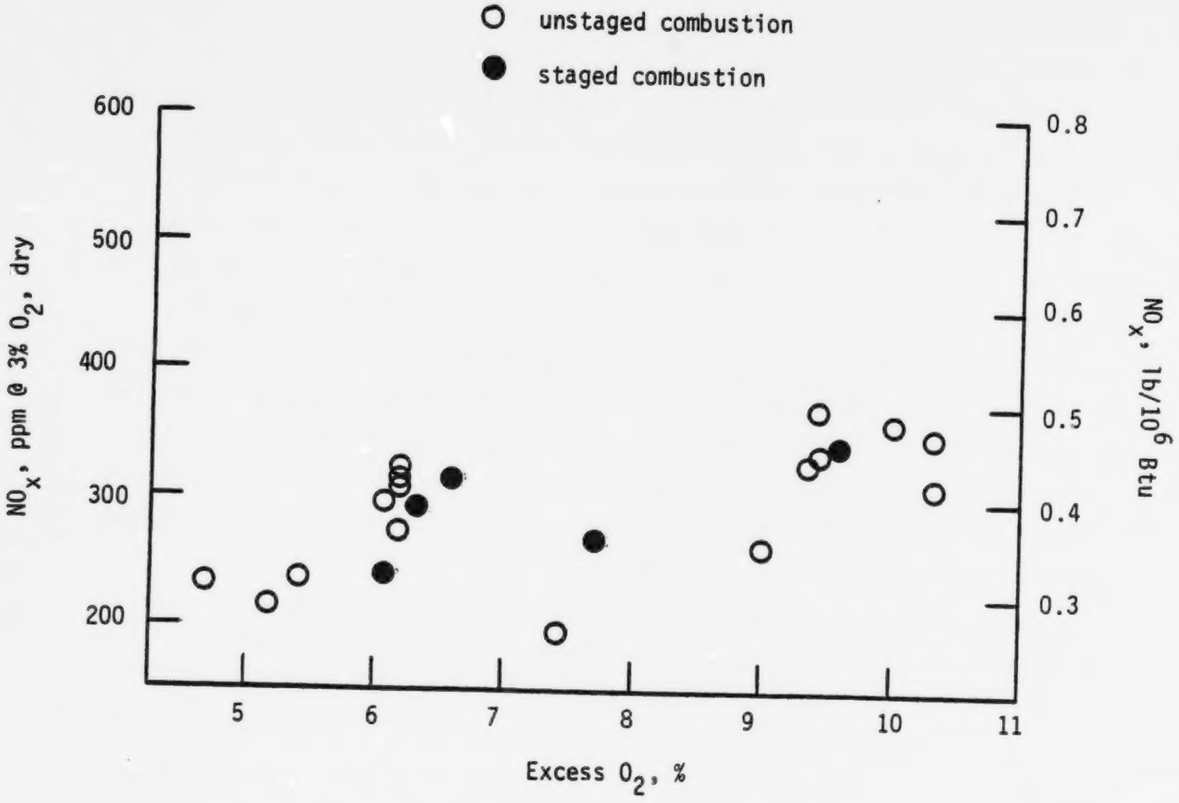


Figure 4.3-15. Short-term emission data for staged combustion in a spreader stoker boiler.

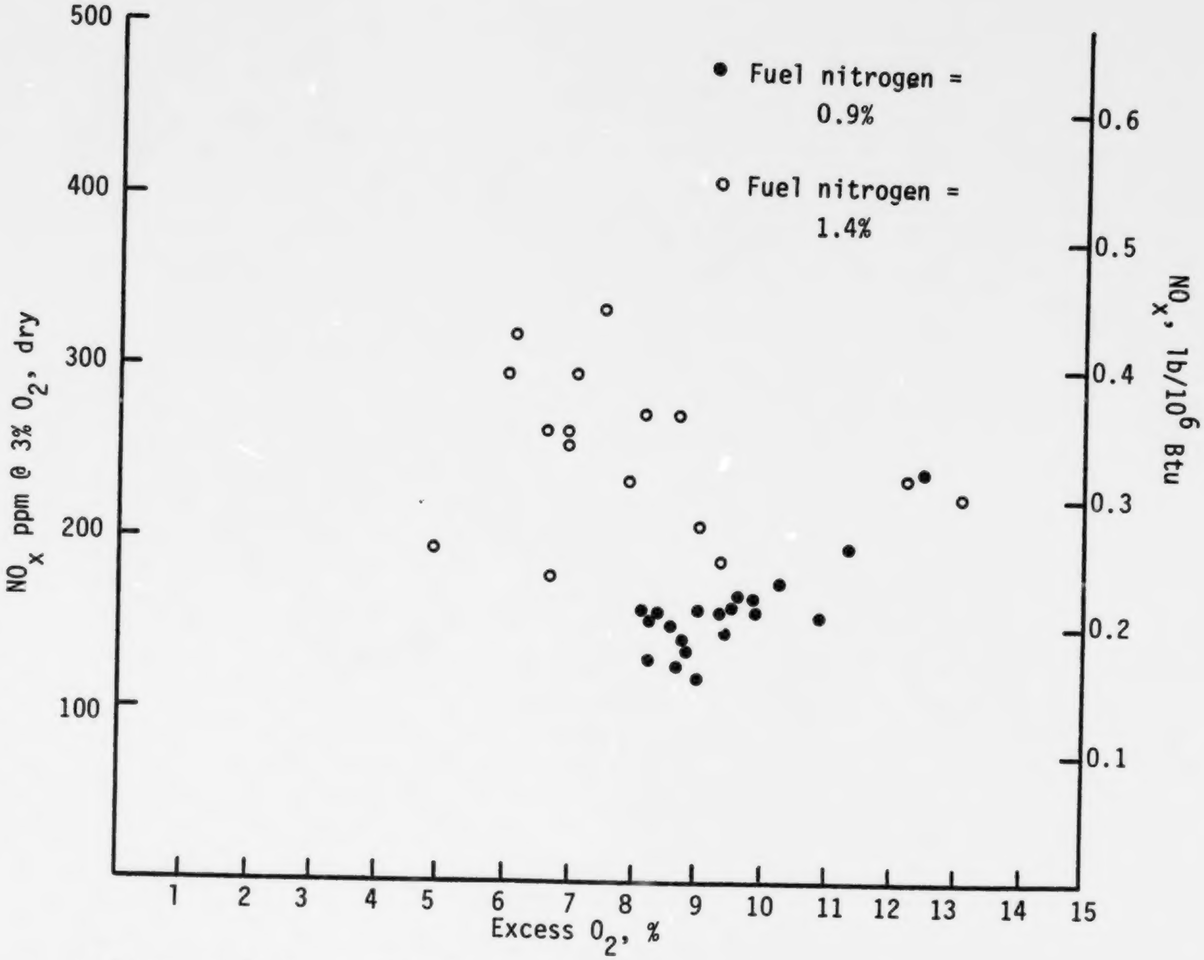


Figure 4.3-16. Short-term emission data for two mass fed stokers. (unstaged and stage combustion)

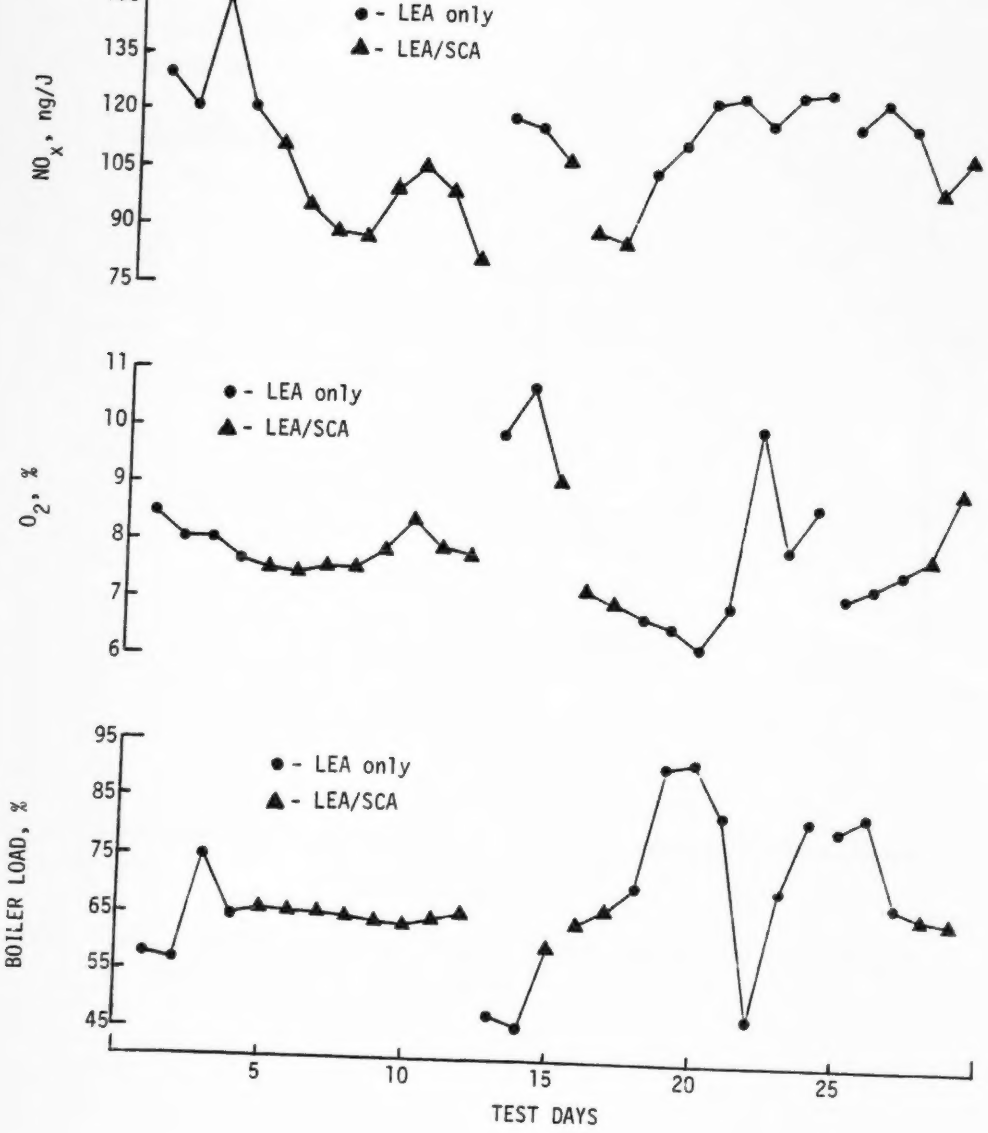


Figure 4.3-17. Continuous monitoring data for LEA/SCA combustion modification on a residual oil-fired boiler at Location IV.

(29 ng/J to 43 ng/J), a slight decrease in POM emissions, no effect on visible emissions or carbon monoxide emissions, and little change in boiler efficiency.

The nitrogen content of the fuel fired during the test was 0.26 percent. Although this nitrogen content is typical of many residual oils currently used as industrial boiler fuels, combustion of higher nitrogen oils (up to 0.8 to 1 percent nitrogen) may become more common in the future in certain areas of the country. Uncontrolled nitrogen oxides emissions tend to be higher when higher nitrogen fuels are fired due to the increased levels of fuel NO_x evolved. No continuous monitoring data were available for industrial units burning high nitrogen oil. However, short-term data were available for boilers firing residual and distillate oils with varying nitrogen contents.

These data were obtained on several different boilers at varying levels of excess air, combustion air temperatures, furnace heat release rates and boiler loads. Boiler capacities ranged from 7,900 to 90,000 kg/hr (17,500 to 200,000 lb/hr) of steam and loads varied from 18 to 100 percent. Using standard statistical techniques, a regression was developed to relate NO_x emissions to the nitrogen content of the fuel at a given level of excess air and combustion air preheat.[104]

Excess air (excess oxygen), combustion air temperature (degree of air preheat), and nitrogen content of the fuel were found to be the major variables influencing NO_x emissions from residual oil-fired boilers. The correlations (1) between NO_x and boiler load and (2) between NO_x and furnace heat release rate were found not to be significant on the units tested.[104] The lack of a correlation between boiler load and NO_x is expected. As boiler load is decreased, heat release rate and thus NO_x formation tends to decrease. However, the excess air rate to the boiler must be increased as load drops, and the increased O_2 leads to more NO_x formation. Therefore, the increase in excess air at lower boiler load offsets the benefits of reduced combustion intensity, and there is little or no net change in NO_x emissions with boiler load.

Figure 4.3-18 shows NO_x emissions as a function of fuel nitrogen content for 3 percent excess O_2 (low excess air) and no combustion air preheat. This figure was constructed using the following regression:

$$E = 24.2\ T^{0.34}\ A^{0.24} + 1055\ N^{1.06} \qquad (4.3\text{-}1)$$

where

E = NO_x emissions (ppm at 3 percent O_2, dry),
T = Combustion air temperature (°R),
A = excess oxygen (mole fraction O_2 in flue gas), and
N = fuel nitrogen content (lb/10^6 Btu)

This regression was developed from 208 short-term data points (see Appendix C - Tables C.4-17, C.4-18, and C.4-20). These data were obtained from several boilers both with and without air preheat. The nitrogen content of the oil fired in the boilers tested ranged from near zero to about 0.8 weight percent.

Equation 4.3-1 shows that NO_x emissions from residual oil units can be reduced by any (or a combination) of three methods:

(1) reducing or eliminating combustion air preheat,
(2) reducing the excess air (LEA operation), or
(3) burning oil with a low nitrogen content.

Figure 4.3-18 represents the NO_x emissions expected at a LEA level of 3 percent O_2 (15 percent excess air) and no combustion air preheat. As the figure shows, NO_x emissions are still a strong function of the fuel nitrogen level. This results from the fact that neither LEA operation nor lower combustion air temperatures are effective in reducing fuel NO_x formation. Other than burning lower nitrogen content oil, the most effective technique for reducing fuel NO_x emissions is staged combustion (see Section 4.3.2).

Short-term data were available for 6 residual oil-fired boilers using staged combustion (See Appendix C). These units burned oils with nitrogen contents of from 0.14 to 0.49 weight percent. These data were normalized to 3 percent excess oxygen and no air preheat and a factor was developed to relate the reduction in NO_x emissions with staged combustion relative to unstaged, LEA operation.[104] The results are shown in Figure 4.3-19. The

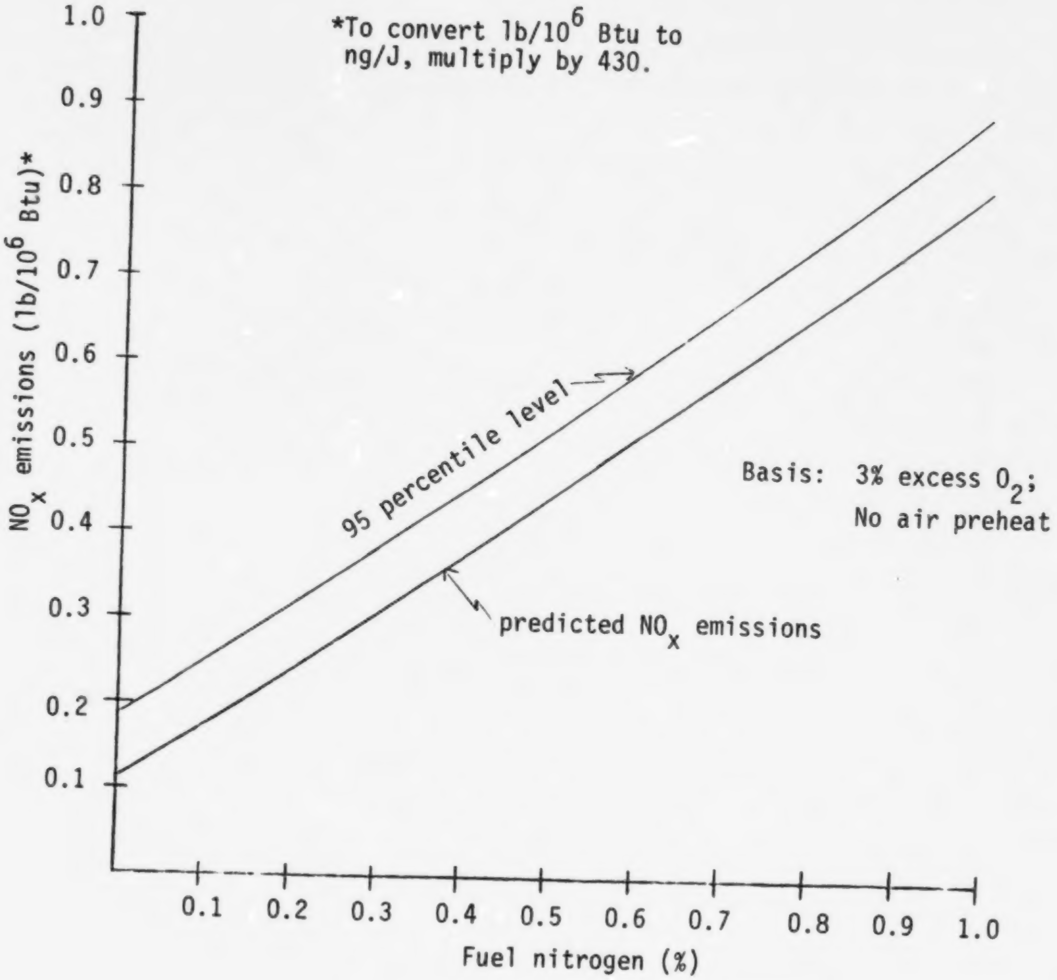


Figure 4.3-18. Predicted NO$_x$ emissions from residual oil units as a function of fuel nitrogen content - LEA controls.

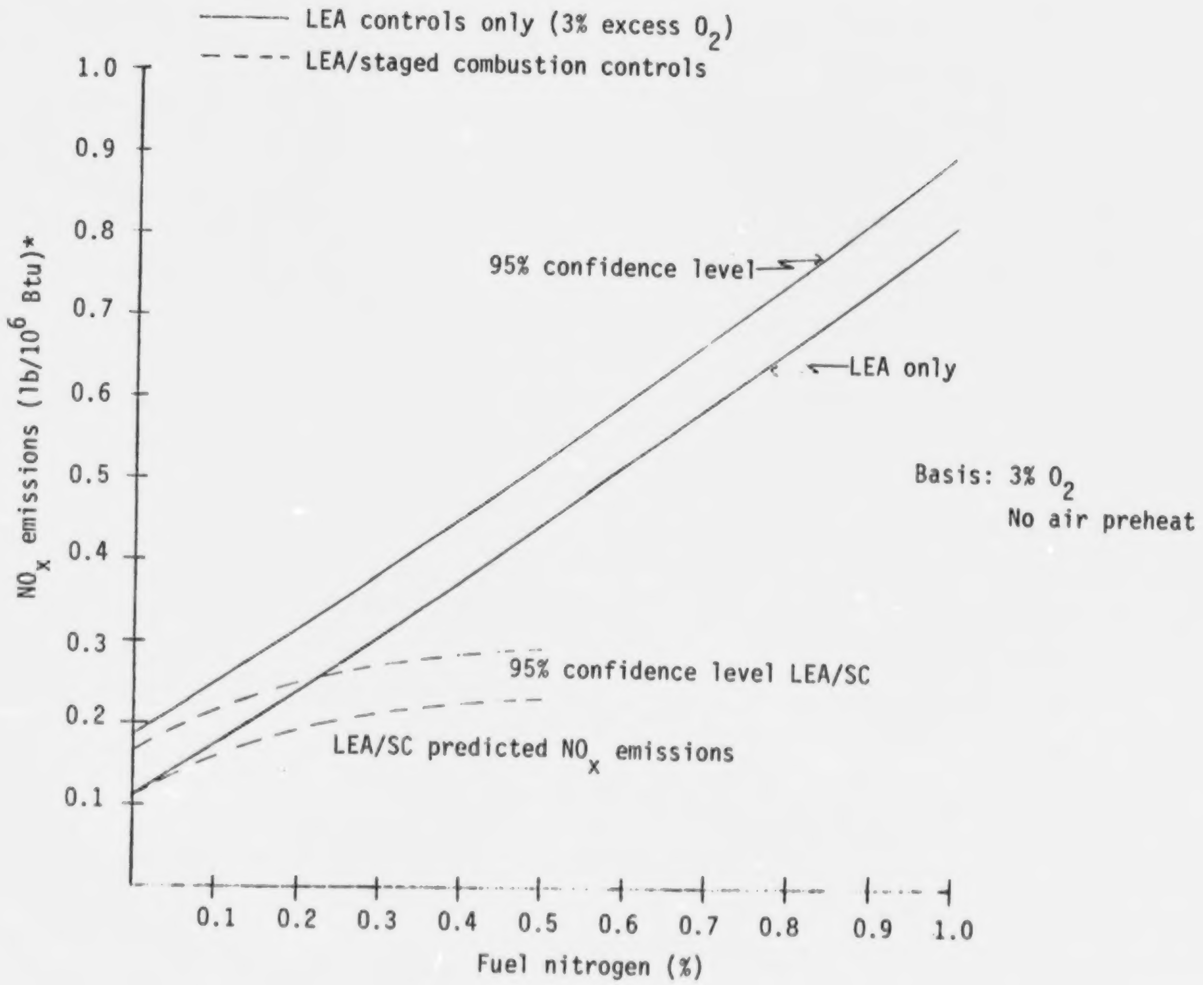


Figure 4.3-19. Predicted NO_x emissions from residual oil-fired boilers vs. fuel nitrogen - LEA and staged combustion controls.

*To convert to ng/J, multiply by 430.

factor describing the effectiveness of staged combustion was found to be a function of fuel nitrogen content. As the nitrogen content of the fuel (and thus potential fuel NO_x emissions) increases, the NO_x reduction achieved by staged combustion increases.

Short-term emission data was also available for a small boiler [7,900 kg/hr (17,500 lb/hr) steam)] firing residual oil with a 0.14 percent nitrogen content and using flue gas recirculation (FGR). Loads ranged from 80 to 85 percent. Sixteen tests with FGR showed average emissions of 78 ng/J (0.18 $lb/10^6$ Btu). Emissions under low excess air operating conditions (3 percent excess O_2, no FGR) were 95 ng/J (0.22 $lb/10^6$ Btu). These data indicate that FGR is somewhat effective in reducing NO_x emissions below the levels achieved with LEA (Reference 128, pp. 315- 367).

4.3.7.3 Distillate Oil-Fired Boilers. No continuous NO_x emission monitoring data were available for distillate oil-fired boilers. However, short-term data, under both unstaged and staged combustion conditions were available. The unstaged data are included with the short-term residual oil data presented in the previous section and used to develop Figure 4.3-18. These data are also shown in Figure 4.3-20.

Fuel NO_x formation in distillate oil-fired boilers is minimal because most distillates have very low nitrogen contents. The most important effect on NO_x emissions from distillate units, is combustion air temperature. The data in Figure 4.3-20 are separated into those tests conducted on boilers equipped with combustion air preheat and those conducted on boilers with little or no air preheat. Nearly all units with combustion air preheat had higher NO_x emissions than boilers without air preheat. Figure 4.3-20 shows that on the average, NO_x emissions from boilers with air preheat were about twice those from boilers without air preheat at a given excess O_2 level. Figure 4.3-20 shows NO_x emissions from boilers without air preheat to be less than 86 ng/J (0.2 $lb/10^6$ Btu).

Figure 4.3-21 shows short-term data from a distillate oil-fired boiler (without air preheat) under staged combustion conditions. The one available emission test under unstaged operating conditions is shown for comparison.

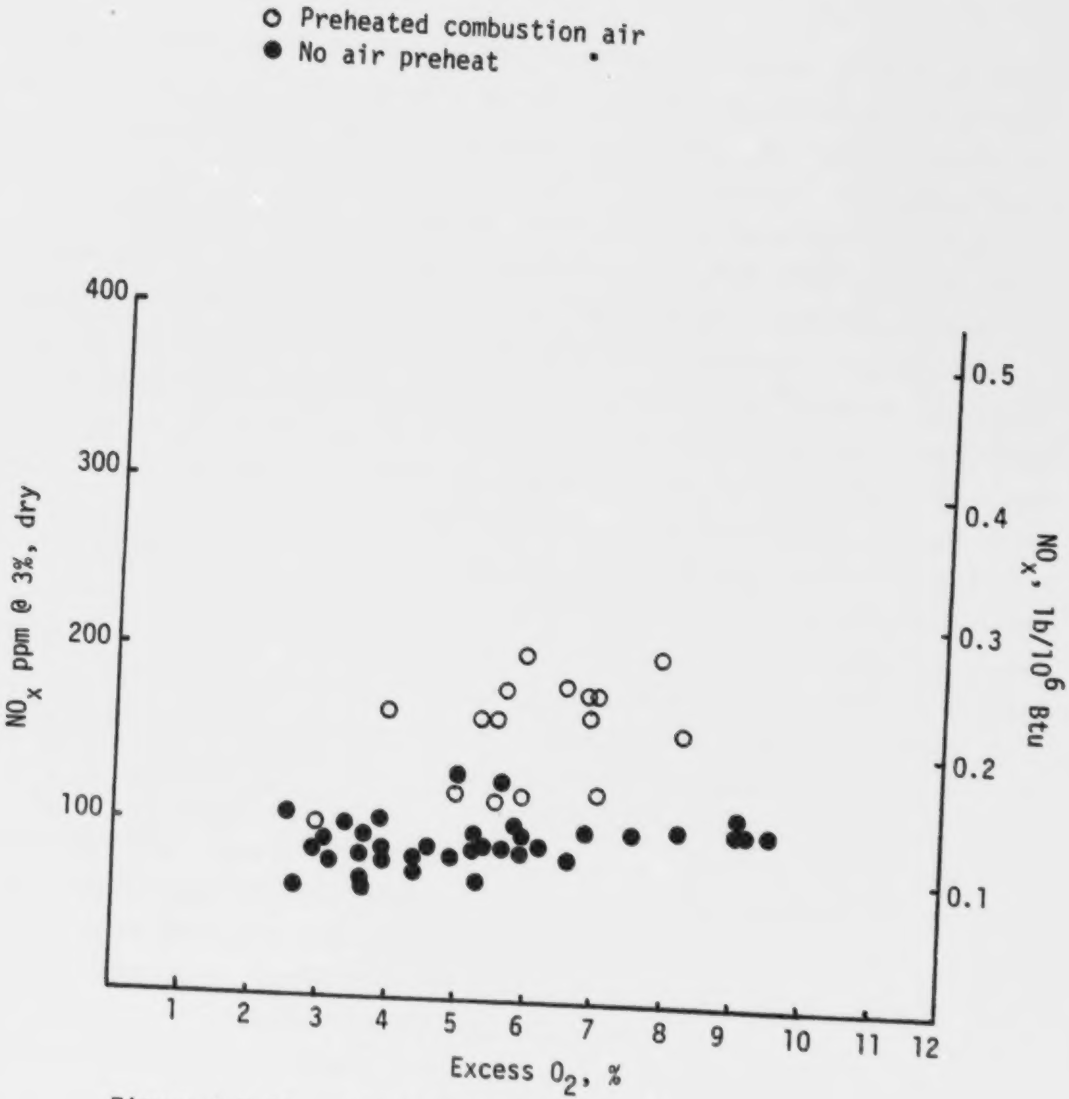


Figure 4.3-20. Short-term emission data for distillate oil-fired boilers.

(unstaged combustion)

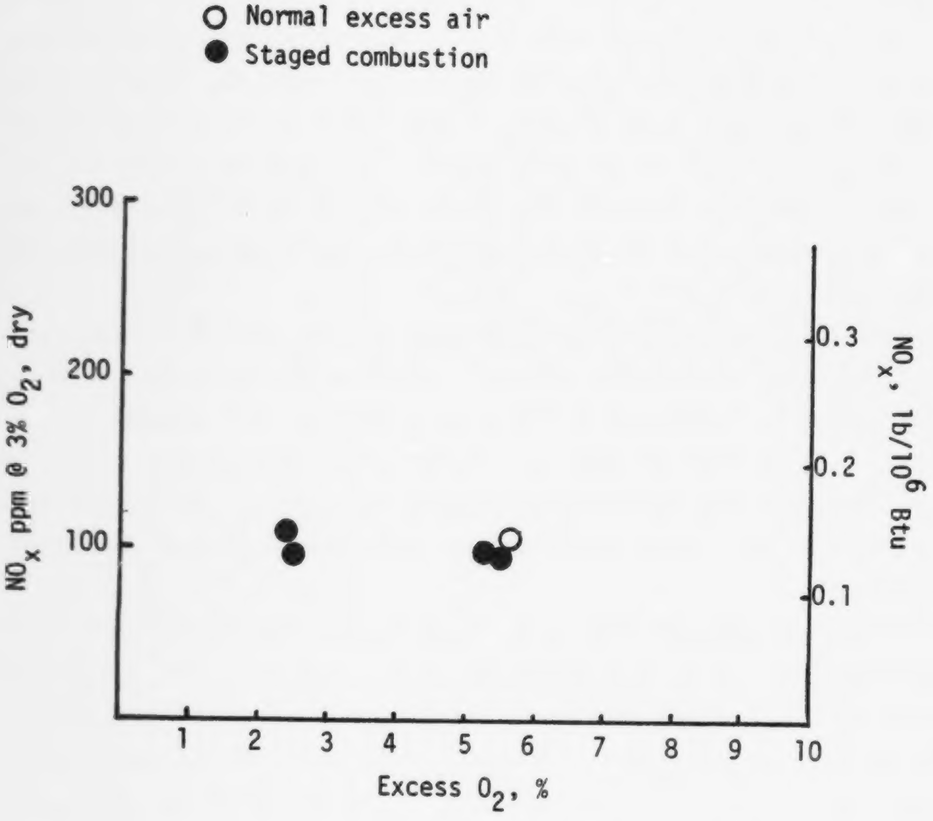


Figure 4.3-21. Short-term data for distillate oil-fired boiler without air preheat. (staged combustion)

This data base is considered too limited to draw any conclusion concerning the effectiveness of staged combustion on distillate oil-fired boilers.

4.3.7.4 Natural Gas-fired Boilers. Continuous NO_x emission data were available for a small firetube natural gas-fired boiler at Location V with a steam capacity of 3130 kg/hr (6960 lb/hr). As shown in Figure 4.3-22, NO_x emissions ranged from 27 to 33 ng/J (0.06 to 0.08 lb/10^6 Btu) over the 21-day test period even though the excess O_2 levels were never less than 5.5 percent.

These data demonstrate the relatively low NO_x emission rate from small natural gas units without air preheat. However, NO_x emissions from larger natural gas units, both with and without combustion air preheat, are generally greater than 43 ng/J (0.1 lb/10^6 Btu), even at low excess air levels. Figure 4.3-23 presents short-term NO_x emission data collected on several natural gas-fired industrial boilers under unstaged combustion conditions.

The use of combustion air preheat on natural gas-fired boilers can have a significant impact on both uncontrolled NO_x emissions and the NO_x levels achievable at low excess air levels. Although there is considerable scatter in the short-term data, (due to variations in heat release rate, combustion air temperature and burner design), the lowest NO_x emissions are generally observed at excess O_2 levels of less than 2.5 percent (approximately 11 percent excess air). [As discussed in Section 4.3.1, the recommended minimum safe excess O_2 levels for gas-fired units range from 0.5 to 3 percent].

Figure 4.3-23 indicates that elimination of combustion air preheat leads to lower NO_x emissions as evidenced by the difference in NO_x emissions between units with and without air preheat. At excess O_2 levels of less than 3 percent, NO_x emissions from units without air preheat are about 86 ng/J (0.2 lb/10^6 Btu) or less. In contrast, emissions from units with air preheat range from 86 to 151 ng/J (0.2 to 0.35 lb/10^6 Btu) at excess O_2 levels of less than 3 percent.

Figure 4.3-24 shows the available short-term emission data for staged combustion in natural gas units. Emissions under normal operating

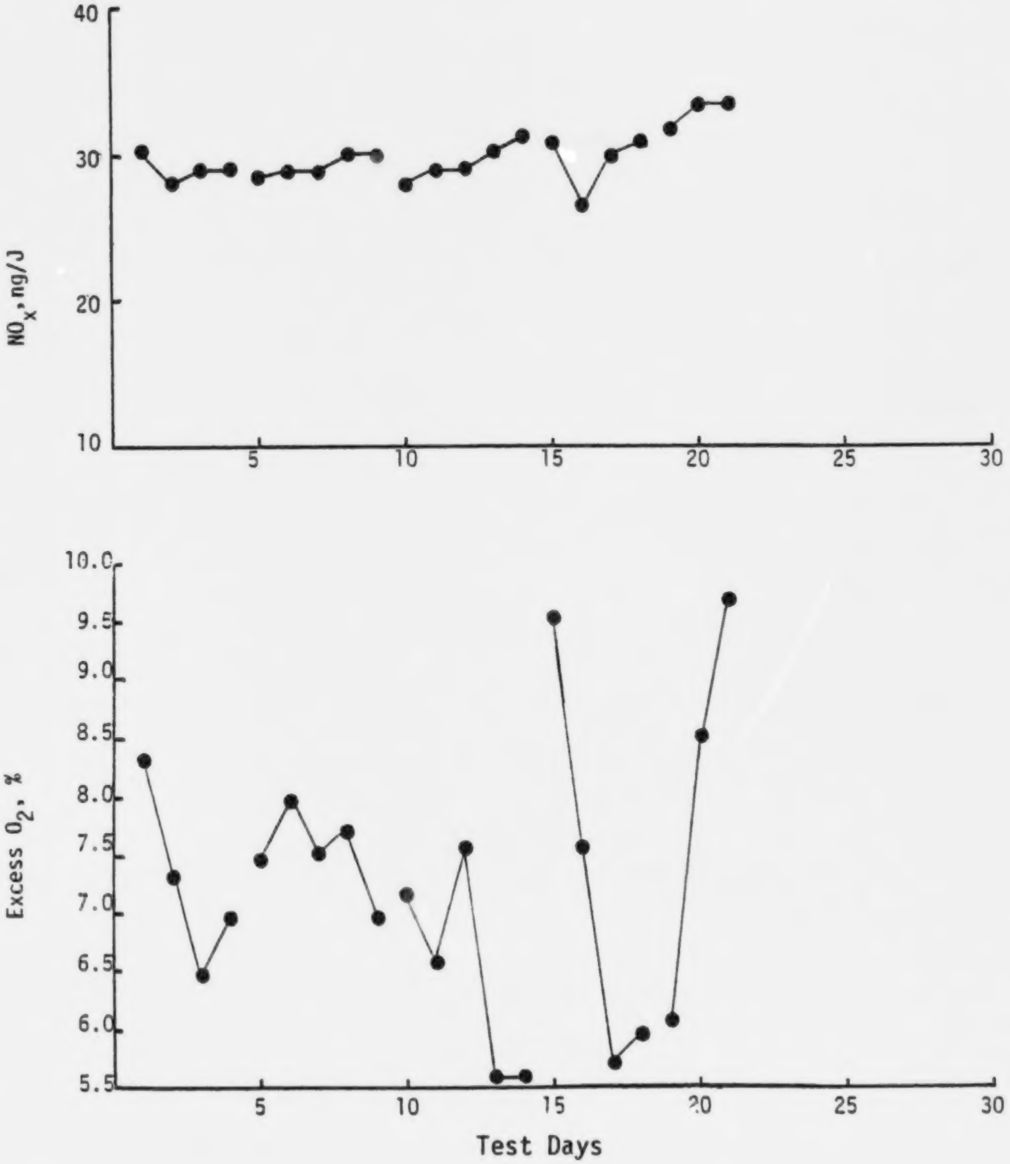


Figure 4.3-22. Continuous NO_x emission data for a small natural gas boiler at Location V.

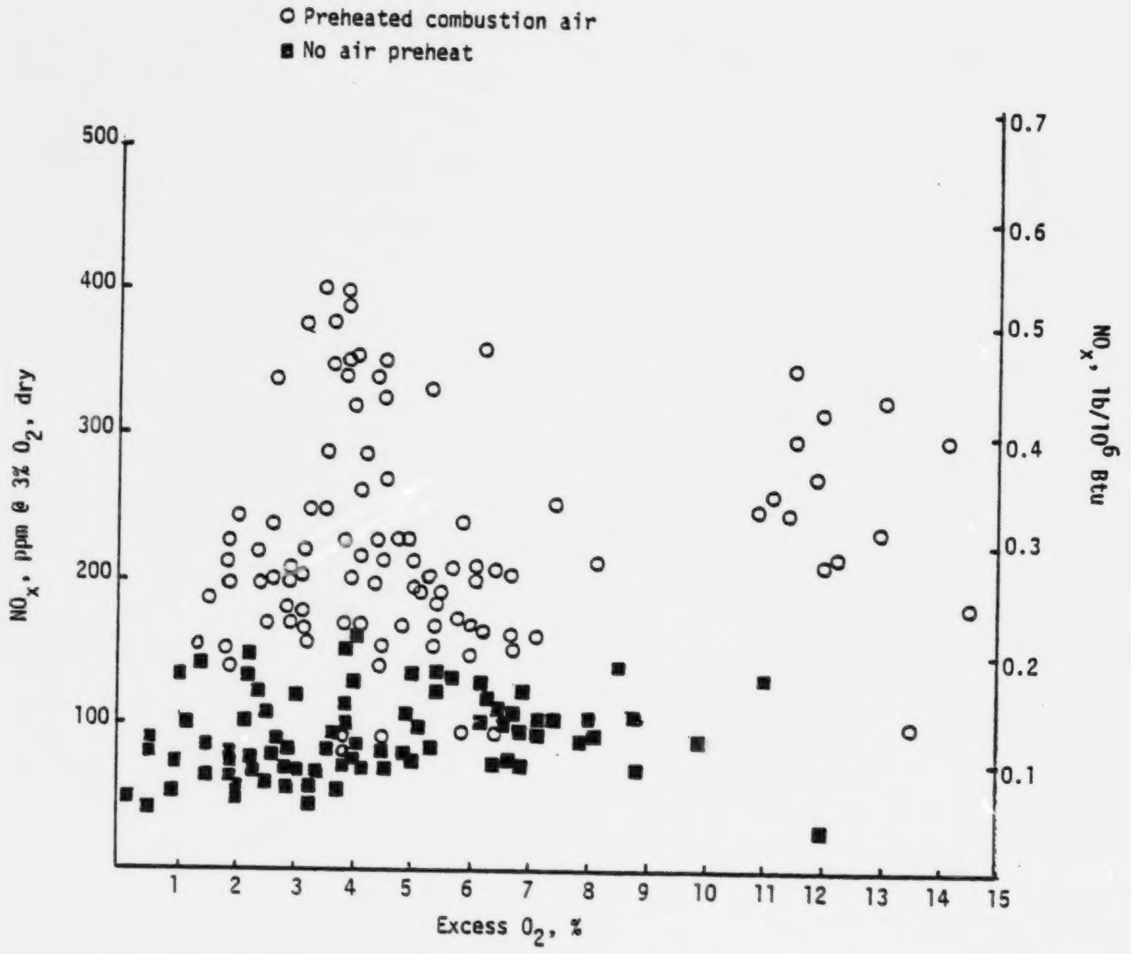


Figure 4.3-23. Short-term emission data for natural gas fired boilers. (unstaged combustion)

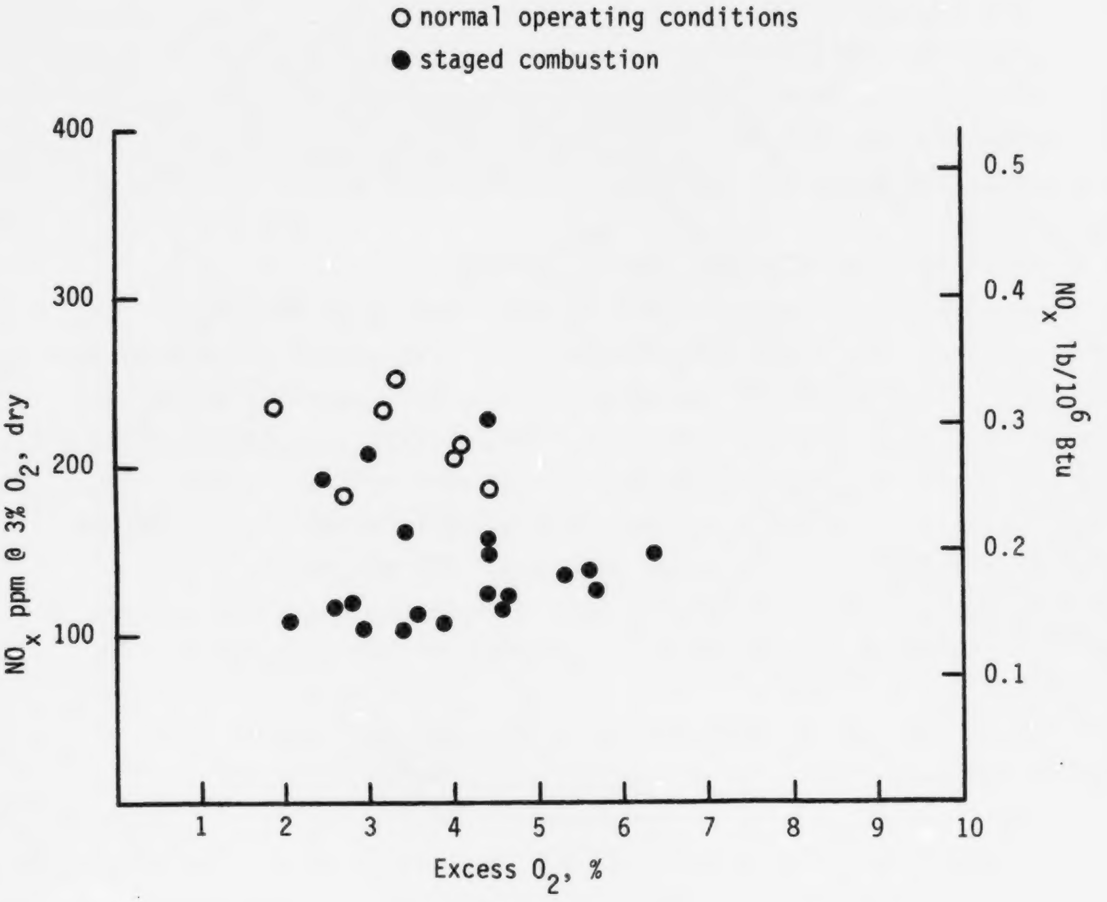


Figure 4.3-24. Short-term emission data for natural gas-fired boiler. (staged combustion)

conditions are shown for comparison. These data were obtained from five boilers, four of which had air preheaters. Staged combustion is somewhat effective in reducing NO_x emissions although considerable scatter is evident. Controlled emissions were 129 ng/J (0.3 lb/10^6 Btu) or less in each test conducted under staged combustion conditions.

The only emission data for flue gas recirculation was obtained on a small firetube unit [8170 kg steam/hr (18,000 lb steam/hr)]. Short-term data showed that FGR reduced NO_x emissions from 28 ng/J (0.07 lb/10^6 Btu) at normal operating conditions to an average 13 ng/J (0.03 lb/10^6 Btu). (Reference 128, pp. 315-367). This data is considered too limited to draw any conclusions concerning the performance of FGR on natural gas-fired boilers.

4.4 POST COMBUSTION TECHNIQUES FOR NO_x CONTROL

Post combustion flue gas treatment (FGT) techniques for control of NO_x emissions use either a gas phase reaction or liquid absorption to treat the flue gas. In most cases the gas phase reaction is between NO_x and NH_3 in the presence of a solid phase catalyst. The catalyst is contained within a fixed or moving bed reactor. The NO_x is converted to N_2 which exits with the flue gas. Systems using a liquid absorption technique contact flue gas with the absorbent in conventional scrubbers. The absorbed NO_x either remains in the scrubbing liquor and is treated in the liquid phase or reacts with a reductant to form N_2 which is liberated and is discharged with the flue gas.[131]

The NO_x FGT systems discussed in subsections 4.4.1 through 4.4.3 include systems designed for NO_x removal only (NO_x-only) as well as processes designed for simultaneous removal of SO_2 and NO_x (NO_x/SO_x). The NO_x-only processes described are fixed bed, moving bed and parallel flow selective catalytic reduction; the NO_x/SO_x processes described are wet scrubbing, and electron beam irradiation. The mechanism by which each of these techniques reduces flue gas NO_x concentration, the applicability of the technique to new industrial boilers, the design or operating factors which influence the NO_x reduction performance of the control technique on an industrial boiler, and any impact these controls may have on the design and operation of the boilers are briefly discussed. No performance data taken by approved EPA methods was available for any of the techniques discussed.

4.4.1 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a technique involving removal of the flue gas NO_x by reacting NO_x with NH_3 in a catalytic reactor to form elemental nitrogen. With the exception of the use of a catalyst it is similar to the ammonia injection NO_x control technique discussed in Section 4.3.

4.4.1.1 Process Description

4.4.1.1.1 System. A generalized SCR process flow diagram is shown in Figure 4.4-1. In this process, ammonia, taken from a liquid storage tank and vaporized, is injected at molar ratios of 0.7-1.2 moles NH_3 per mole of NO_x and mixed with the flue gas prior to the catalytic reactor. The flue gas passes through the catalyst bed where NO_x is reduced to N_2. Typically, a 1.0 mole ratio of NH_3 to NO yields a 90 percent reduction in NO_x emissions. The flue gas exits the reactor and is sent to the air preheater and, if necessary, further treatment equipment for removal of particulates and SO_2. Flue gas must enter the reactor at 350-400°C (662 - 752°F) since it is in this temperature range that catalysts show the optimum combination of activity and selectivity. The catalysts used in most SCR processes are oxides of non-noble metals which have shown the best combination of high reactivity and resistance to SO_2 and SO_3 poisoning.

The type of fuel burned in an industrial boiler plays an important role in the selection of the catalyst bed configuration. The following discussion presents three common bed configurations and the appropriate application of these bed types to coal-, oil-, and gas-fired boilers.

Moving Bed Reactor. Moving bed systems for selective catalytic reduction of NO_x are applicable only to flue gas streams containing particulate concentrations less than .998 g/dNm^3 (.437 grain/SCF). Particulate concentrations for all coals are higher, on the order of 0.998-4.99 g/dnm^3 (.437-2.18 grain/SCF). In moving bed reactors the catalyst circulates through the reactor and is screened to remove particulates. A second possibility would be the use of a moving bed design which would permit the

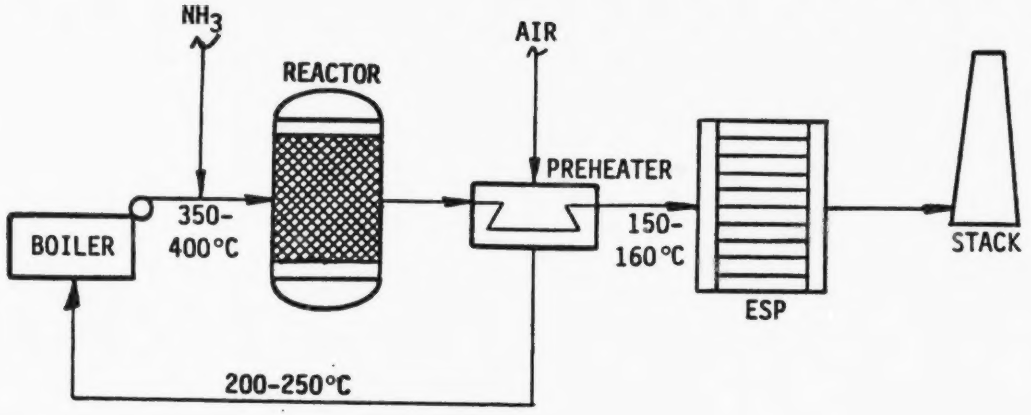

NH3
AIR
REACTOR
PREHEATER
BOILER
350-
400°C
150-
160°C
ESP
STACK
200-250°C

Figure 4.4-1. Typical industrial boiler SCR system.[132]

periodic removal of catalyst for cleaning. However, it is not expected that moving bed systems will be used for coal-fired industrial boiler applications.[133]

Parallel Flow Reactor. The distinguishing aspect of this process is that the catalyst is produced in a variety of shapes including honeycomb, pipe, or plate configurations. The catalyst shapes allow particulate-laden flue gas to pass through the reactor with no inertial impaction of the particles while the NO_x is transported to the catalyst surfaces by basic diffusion. These catalysts can handle the particulate levels of boilers firing all fuels.

The reactors used are similar to standard fixed packed bed units discussed below. The catalyst is usually prepared in small modules and manually stacked within the reactor. The specific arrangement will depend on the particular process under consideration.[134]

Fixed Packed Bed Reactor. Fixed packed bed systems for selective catalytic reduction of NO_x are applicable only to flue gas streams containing particulate emissions of less than .021 g/dNm^3 (0.009 grain/SCF). Particulate emissions for all coals are higher than this level. For this reason, fixed packed bed SCR systems are not considered applicable to coal-fired boilers by process vendors.[135]

Although most SCR processes are NO_x-only, one parallel flow reactor arrangement using a copper based catalyst is capable of simultaneous NO_x/SO_x emission reduction. In this case, the copper-based catalyst functions as an SO_2 adsorbent as well as a NO_x reduction catalyst. A generalized flow diagram of this type process is shown in Figure 4.4-2. In the reactor, SO_2 reacts with CuO and oxygen to form $CuSO_4$. Copper sulfate then promotes the reduction of NO with NH_3. Several reactors are operated in "swing" operation, that is, when one reactor is saturated it is taken offline for regeneration and a freshly regenerated reactor is brought on line.

4.4.1.1.2 Development status. SCR is not considered to be a commercially demonstrated control technology for coal-fired sources in the United States. SCR processes have been used commercially in Japan on gas-, distillate oil-, and residual oil-fired industrial boilers and SCR processes

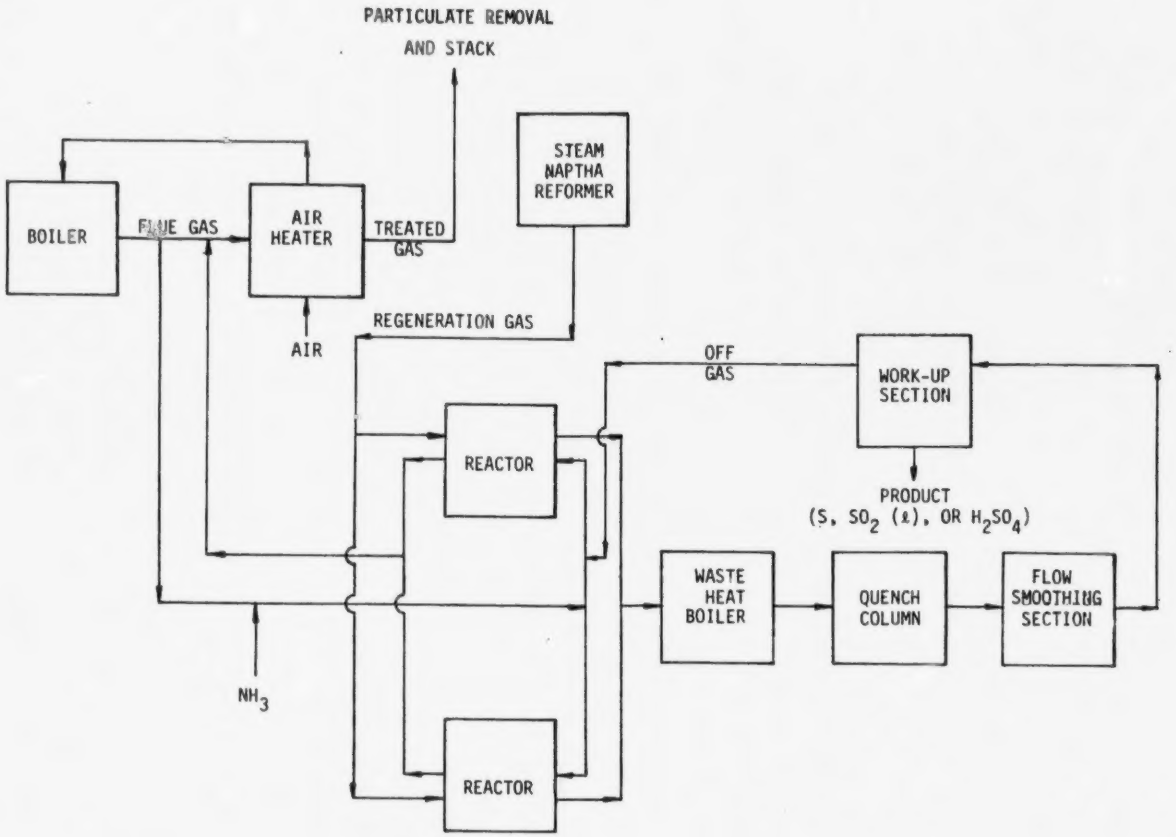

PARTICULATE REMOVAL
AND STACK
BOILER
FLUE GAS
AIR HEATER
TREATED GAS
AIR
STEAM NAPTHA REFORMER
REGENERATION GAS
OFF GAS
WORK-UP SECTION
REACTOR
PRODUCT
(S, SO_2 (ℓ), OR H_2SO_4)
NH_3
WASTE HEAT BOILER
QUENCH COLUMN
FLOW SMOOTHING SECTION
REACTOR

Figure 4.4-2. Flow diagram of a simultaneous NO_x/SO_x SCR system.[136]

on coal-fired utility boilers are currently under construction in that country. Ongoing studies in the United States are investigating NO_x-only and NO_x/SO_x SCR performance with coal combustion in pilot-scale facilities. There is no full-scale U.S. or Japanese SCR installation with documented performance in accordance with EPA test methods, although removals in excess of 90 percent have been reported for Japanese gas- and oil-fired boiler SCR applications. The earliest U.S. commercial demonstrations are planned for 1982 on two low-sulfur oil-fired utility boilers in Southern California.[135] SCR technology is also expected to be applied to steam generators involved in thermally-enhanced oil recovery projects in California. EPA is sponsoring two pilot scale evaluations of the technology on coal-fired utility boilers. The Electric Power Research Institute (EPRI) is also sponsoring a coal-fired utility boiler SCR pilot plant.

4.4.1.1.3 Applicability. SCR is applicable to all industrial boiler types. Japanese SCR technology relies primarily on two catalyst reactor designs: fixed bed and parallel flow. The fixed bed reactor which consists of tightly packed catalytic granules, can become plugged if there is high grain loadings in the flue gas. Therefore, the Japanese developers recommend it only for gas-fired boilers.[138] In the parallel flow reactor, the catalyst arrangements resist plugging and blinding of catalytic surfaces due to dust in the flue gas and are recommended when burning residual oil and coal.[134] All three U.S. pilot-scale studies use the parallel flow design.[137]

The flue gas flow rate from the boiler and the design NO_x control level determine the catalyst volume necessary. Increases in either will increase the required reactor size. The uncontrolled NO_x concentration is primarily a function of fuel type used to fire the boiler. Higher NO_x concentrations require larger NH_3 storage and vaporization equipment; reactor size is not significantly affected by NO_x concentration for a constant control level. Boiler load can affect several parameters including flue gas temperature, flow rate and NO_x concentration. Temperature control equipment may be necessary to accommodate large boiler load variations. Where such variations are expected, some equipment overdesign may be warranted to insure a constant control level.[139]

The impacts of parallel flow and fixed packed bed SCR systems on boiler operation and maintenance should be minor. The primary impact is on the air preheater since dry residual NH_3 will react with SO_3 as flue gas temperature decreases to form ammonium bisulfate and ammonium sulfate. Bisulfate is formed by a one-to-one reaction between NH_3, SO_3, and H_2O in the flue gas:

$$NH_3(g) + SO_3(g) + H_2O(g) \rightarrow NH_4HSO_4\ (s)$$

Bisulfate is corrosive when it condenses on unprotected surfaces; therefore, use of corrosion-resistant material is warranted where bisulfate deposits are probable. A minimum NH_3 injection ratio is also recommended for low NH_3 emissions and bisulfate formation. Heat exchanger temperatures must be kept above bisulfate formation and acid condensation points and should be equipped with a cleaning apparatus to remove any deposits of these compounds.[140]

There are some potential adverse environmental impacts associated with the use of SCR, including gaseous NH_3 emissions, disposal of ammonium bisulfate or ammonium sulfate and disposal of spent catalyst.

4.4.1.2 Factors Affecting Performance. An important design variable with respect to SCR performance is the space velocity which is expressed as the volume of catalyst required to treat one volume per hour of flue gas. Space velocity requirements vary with catalyst formulation, catalyst shape, and control level. Typical values of space velocity for various catalyst shapes are shown in Table 4.4-1. Also shown are other catalyst design variables such as catalyst dimensions, gas velocities, bed depth and pressure drop. Ranges of values are used since specific values are different for each catalyst. The values shown are for a design NO_x removal of 90 percent and an NH_3/NO_x mole ratio of 1:1.[141]

Both NH_3/NO_x ratio and space velocity will change with removal level. The NH_3/NO_x mole ratio will range from 0.7-1.2 for control levels of 70 to

TABLE 4.4-1. CATALYST DESIGN VARIABLES FOR VARIOUS CATALYST SHAPES (Basis: 90% NO_x removal at NH_3/NO_x ratio of 1:1, 350-400°C)[141]

	Honeycomb (metallic)	Honeycomb, tube (ceramic)	Parallel Plate	
			(Ceramic)	Metallic)
Catalyst size (mm)				
Thickness	1	2.3-5	8-10	1
Opening	4-8	6-20	8-14	5-10
Gas velocity (m/sec)[a]	2-6	5-10	5-10	4-8
Bed depth (m)	1-2	1.5-5	4-6	2-5
SV (1,000 hr^{-1})[b]	5-8	4-8	1.5-3	2-4
Pressure drop (mmH_2O)	40-80	40-160	80-160	60-120

[a] Velocity at 350-400°C in open column (superficial velocity).

[b] Gas volume (Nm^3/hr)/catalyst bed volume (m^3).

90 percent.[142] The operating temperature range for most of these processes is about 300-500°C (527-932°F), though more efficient NO_x removal usually occurs in the higher portion of this range. To maintain the reactor temperature at desirable operating levels during periods of reduced boiler load, most process vendors recommend bypassing a part of the flue gas around the economizer. In some pilot plant and larger operations, auxiliary heaters have been used to maintain reactor temperatures during turndown.[143]

4.4.1.3 Emissions Data. While there are a number of commercial SCR systems presently treating oil-fired flue gas in Japan, the data on these units are limited mostly to a single reported removal level. These tests give only point values of removal and not a set of continuous data. In addition, the test method and boiler operating conditions are not given.

The results from several catalyst life tests conducted in Japan demonstrate NO_x removal efficiencies of 70 to 90 percent or greater for low sulfur, high sulfur, and heavy oil-fired utility boilers. $NO_x:NH_3$ ratio for these tests was equal to 1. Other operating parameters were not specified.

4.4.2 Wet Scrubbing

Wet FGT processes are, in most cases, designed to take advantage of technology already available from previously developed FGD systems. Most wet FGT processes were originally designed as simultaneous NO_x/SO_x systems. Unfortunately, NO, which represents the majority of industrial boiler NO_x emissions has an extremely low solubility in aqueous solutions. NO_2, which is the lesser component of industrial boiler NO_x emissions, is much more soluble than NO although the solubility of NO_2 is poor relative to SO_2. Therefore, the major task associated with any wet NO_x removal process is the absorption of the NO_x by the scrubbing solution where it can be concentrated and converted into other nitrogen compounds.

There are two common methods of removing NO_x from flue gas, direct absorption of NO_x in the absorbing solution and gas-phase oxidation to convert the relatively insoluble NO to NO_2 followed by absorption. Wet NO_x removal processes are generally classified as absorption or oxidation processes, depending on whether or not the flue gas is treated with a gas-phase oxidant before absorption. Additionally, each of these classifications is divided based on the fate of the NO_x after it has been absorbed by the scrubbing solution. Processes which reduce the absorbed NO_x either partially or completely to molecular nitrogen or complex nitrogen-sulfur compounds are classified as reduction processes. Processes which do not reduce the absorbed NO_x are absorption processes. Absorption-oxidation processes involve a absorption of NO and liquid phase oxidation to nitrates which must be removed by wastewater treating techniques. Thus, the wet NO_x processes can be categorized into one of the following groups: oxidation-absorption-reduction, oxidation-absorption, absorption-reduction, or absorption-oxidation. A very simplified flow diagram for a wet NO_x/SO_x process is shown on Figure 4.4-3. The various processes developed in each of these categories are described in the technology assessment report on NO_x flue gas treatment listed in Table 4-1.

Development to date for all of these processes has not proceeded beyond the pilot plant stage. Numerous processes have been piloted on coal and oil-fired utility boilers but to date prototype plans have all been abandoned in favor of SCR development. Major problems encountered include high energy penalties, difficult water treatment problems, and high sorbent replacement rates.

At least two vendors are currently offering absorption-oxidation systems for oil-fired steam generator applications for thermally enhanced oil recovery operations. No commercial applications exist however and no pilot or prototype data have been published.

4.4.3 Electron Beam Irradiation

This dry process utilizes an electron beam to bombard the flue gas, removing NO_x and SO_2 in the process. A block flow diagram for the process is shown in Figure 4.4-4.

Flue gas downstream of the air preheater is passed through a "cold side" ESP to remove particulates. After a small amount of ammonia is added, the gas enters a reactor, with a residence time of 1-20 seconds, at 373 K (100°C) where it is bombarded with an electron beam at the rate of 10^5-10^6 rad/sec.

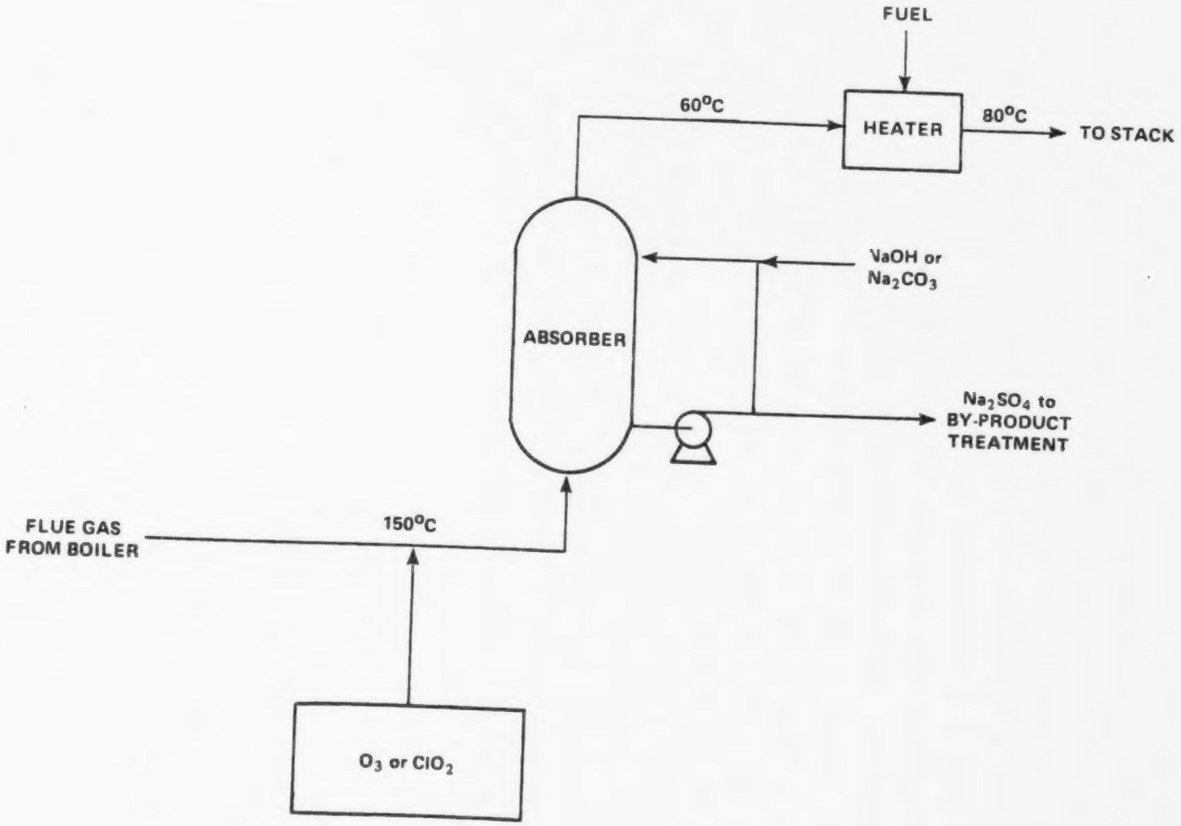

FUEL
HEATER
60°C
80°C
TO STACK
ABSORBER
VaOH or Na_2CO_3
Na_2SO_4 to BY-PRODUCT TREATMENT
FLUE GAS FROM BOILER
150°C
O_3 or ClO_2

Figure 4.4-3. Generalized flow diagram for wet NO_x/SO_2 processes.[144]

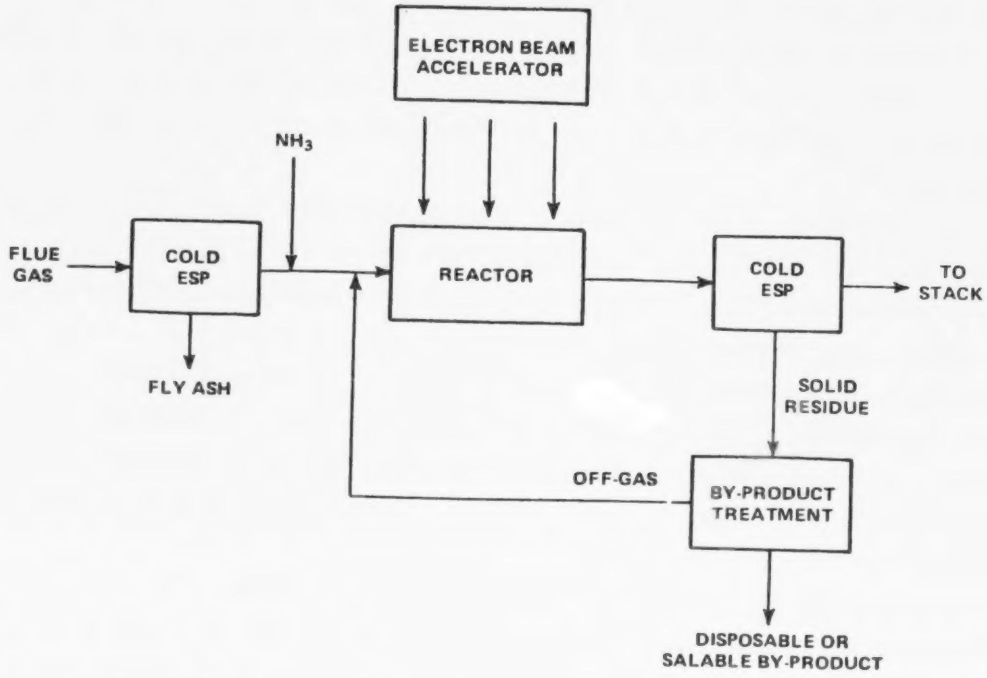

ELECTRON BEAM ACCELERATOR
NH₃
FLUE GAS
COLD ESP
REACTOR
COLD ESP
TO STACK
FLY ASH
SOLID RESIDUE
OFF-GAS
BY-PRODUCT TREATMENT
DISPOSABLE OR SALABLE BY-PRODUCT

Figure 4.4-4. Process flow diagram for the Ebara-JAERI electron beam process.[145]

The key subsystem of this process is the electron beam accelerator. Control of this unit's power supply is based upon inlet composition, flow rate, and temperature of the flue gas. (The penetration of the gas stream by the beam requires a unique discharge pattern and other special design considerations.) A powder containing both ammonium nitrate and sulfate is generated by an unknown reaction mechanism. The gas is then passed through a second ESP to remove the solid by-product. The by- product treatment system is still being developed. Various methods being investigated include thermal decomposition in the presence of an inert gas, steam roasting with CaO, or steam roasting with H_2O. The byproduct may eventually be useful as a fertilizer.[150]

The Ebara Manufacturing Company in conjunction with Japan Atomic Energy Research Institute (JAERI) has operated a 1000 Nm^3/hr pilot plant treating flue gas from an oil-fired boiler. In 1976, Ebara began operating a 3000 Nm^3/hr pilot plant on the off-gas from an iron ore sintering furnace at Nippon Steel. This process is licensed in the U.S. by Avco- Everett Research Laboratory. The U.S. Department of Energy (DOE) is funding development of an electron beam process offered by Research- Cottrell. Pilot unit tests with flue gas are scheduled, however, the details of the program are not yet available.

4.5 PRE-COMBUSTION TECHNIQUES FOR PM, NO_x, AND SO_2 CONTROL

Pre-combustion techniques considered for reducing PM, NO_x, and SO_2 emissions from industrial boilers include the use of naturally occurring clean fuels, physically or chemically-cleaned fuels, and synthetic (coal-derived liquid or gaseous) fuels. A technique for reducing particulate emissions from oil-fired industrial boilers, involving use of an oil/water emulsion, is also considered as a pre-combustion emission control technique.

Naturally-occurring clean fuels discussed in this section are raw low sulfur coal and raw low sulfur oil which are low enough in sulfur content to meet SO_2 emission limits with no additional controls. The fuel cleaning processes discussed in this section are physical coal cleaning (PCC) and hydrodesulfurization (HDS) of oil. These processes are primarily designed to control SO_2 emissions by reducing the sulfur content of the fuel. However, they may also aid in the control of particulate emissions by simultaneously reducing the ash content of the fuel. Oil cleaning may result in reduced NO_x emissions due to reduction of fuel nitrogen content by hydrotreating.

The synthetic fuels discussed are low-Btu gas (LBG) and solvent refined coal (SRC). LBG is derived from the gasification of coal and may be burned in a gas-fired boiler as an alternative to a coal-fired boiler with conventional emission controls. SRC is either a solid or a liquid boiler fuel derived from noncatalytic coal liquefaction processes which produce a fuel substantially reduced in ash and sulfur and potentially low in fuel-bound nitrogen. These fuels may replace coal and residual oil use in some industrial boilers.

The water/oil emulsion technique involves preparing an oil fuel with a sufficient amount of water to increase the fuel atomization. Unburned carbon particulate emissions are reduced as a result of the improved combustion conditions which result.

The applicability of each of these pre-combustion PM, SO_2 and NO_x emission control techniques to industrial boilers, the design or operating factors which influence their pollutant reduction performance, and the mechanism by which they reduce emissions is discussed in the following subsections. No performance data are presented for any of the pre-combustion emission control techniques because their performance is either obvious (in the case of naturally-occurring clean fuels) or has yet to be proven (e.g., synfuels or oil/water emulsions).

4.5.1 Naturally-Occurring Clean Fuels

The naturally occurring clean fuels of interest are low sulfur coal and low sulfur fuel oil. Low sulfur coal is defined as run-of-mine (ROM) coal which can comply with a given emission standard. Where no emission standard has been delineated, coals with sulfur contents of less than 1 percent by weight are considered low sulfur.[146]

The sulfur content of United States coals is quite variable. While 46 percent of the U.S. total reserve base can be identified as low sulfur coal because its sulfur content is less than 1 percent, 21 percent ranges between 1 percent and 3 percent in sulfur, and an additional 21 percent contains more than 3 percent sulfur. The sulfur content of 12 percent of the coal reserve base is unknown, largely because many coal beds have not been mined.

Nearly 85 percent of the reserve base of less than 1 percent sulfur coal is located in states west of the Mississippi River. The bulk of the western coals are, however, of a lower rank than the eastern coals. On a heat content basis, it is estimated that at least 20 percent of the nation's reserve of low sulfur coal is in the east.[146]

Low sulfur western coals can be burned in underfeed and traveling grate stokers as long as they are designed with sufficient control of undergrate air to handle any caking that may occur. Caking causes an uneven ash layer to form on the grate which reduces combustion efficiency unless undergrate air can be distributed properly. It has been reported that current designs of some spreader stokers cannot handle caking coals because they lack the ability to control undergrate air distribution.[147] Since design changes to incorporate the necessary air distribution system have not been demonstrated, the use of those low sulfur coals which cake or have a low ash fusion temperature is not applicable to these stokers. Other low sulfur coals such as eastern bituminous, which do not cake or have a low ash fusion temperature, can be burned in underfeed and traveling grate stokers. The demonstrated reserve base of low sulfur eastern bituminous coal as of January 1, 1974, was greater than 24 billion metric tons.[148]

Some spreader stokers of current design also cannot handle coals with ash fusion temperatures below 1477 K (2200°F), which are typical for many low sulfur western coals (e.g., the Wyoming subbituminous, Utah bituminous and the lignites.)[149]

Pulverized coal boilers can be designed for almost any type of coal. The initial choice of coal will determine the type of pulverizer used, the tube spacing in the boiler and superheater (low ash fusion temperature coals require greater spacing), and the type of materials used in the furnace wall.[150]

In 1976 domestic refinery capacity for producing fuel oil from low sulfur crude was 231,000 m^3/day (1,452,000 bbl/day), with the difference made up by imports. In contrast to low sulfur coal, low sulfur fuel oil derived from naturally-occurring low sulfur crude is readily applicable to all boiler types and sizes that burn a similar grade of fuel.[151]

There are no factors affecting the applicability of naturally-occurring low sulfur coal or oil to reduce SO_2 emissions, except the actual sulfur content of the fuel. However, the higher resistivity of the fly ash from the combustion of low sulfur coal will affect the design of an ESP relative to that for medium to high sulfur coal. The effect of resistivity on ESP performance is discussed in Subsection 4.1.1.

4.5.2 Physical Coal Cleaning

Physical coal cleaning is the generic name for all processes which remove inorganic impurities from coal, without altering the chemical nature of the coal. Basically, a coal cleaning plant is a continuum of technologies rather than one distinct technology.[152] Each coal cleaning plant is a uniquely-tailored combination of different unit operations determined by the specific coal characteristics and by the commercially dictated processing objectives.

Overall process design philosophy in coal cleaning plants is to use step-wise separations and beneficiations, with a goal of eventually treating small, precise fractions of the feed with the more sophisticated and specific unit operations. In this way, the least costly technologies are applied to large throughputs and the more costly to much smaller throughputs. A characteristic of this design philosophy is that multiple product streams evolve, each with its own set of size and purity properties. In conventional cleaning plants the separate product streams are blended prior to shipment, to produce a composite coal meeting the consumer's specifications. Within the context of supplying industrial boilers with small quantities of relatively low-sulfur fuel, opportunities exist for premium low-sulfur coals to be segregated from the final blending operation and targeted for specialty markets.[153]

4.5.2.1 Process Description

4.5.2.1.1 System. In a modern PCC plant coal is typically subjected to: size reduction and screening, separation of coal from its impurities, and dewatering and drying. Commercial PCC methods are currently limited to separation of the impurities based on differences in the specific gravity of coal constituents (gravity separation) and on the differences in surface properties of the coal and its mineral matter (froth flotation).[154] A generalized physical coal cleaning schematic is shown in Figure 4.5-1.

Five general levels of coal cleaning are used to categorize the degree of treatment to which a coal has been subjected. These levels are:

Level 1 -- Crushing and sizing
Level 2 -- Coarse size coal beneficiation
Level 3 -- Coarse and medium size coal beneficiation
Level 4 -- Coarse, medium, and fine size coal beneficiation
Level 5 -- "Deep cleaning" coal beneficiation

Level 1 processes are generally used to size raw coal to user specifications, and to remove overburden. No washing is done and the entire process is dry.

Levels 2 and 3, in addition to crushing and screening raw coal also perform a minimum of cleaning. Level 2 provides for removal of only coarse pyritic sulfur. Level 3 is basically an extension of Level 2 in that both the coarse and medium size fractions obtained from screening are washed whereas in Level 2 only the coarse fractions are washed.[155]

Level 4 systems provide high efficiency cleaning of both coarse and medium coal fractions with lower efficiency cleaning of the fines. The primary difference between Level 4 and the lower cleaning levels is the use of heavy media processes for cleaning specific size fractions above 28 mesh. For particles smaller than 28 mesh, cleaning by froth flotation is most commonly used. Level 4 systems accomplish free pyrite rejection and improvement of heat content.[156]

Level 5 coal preparation systems are unique in that two products are produced, a high quality, low sulfur, low ash coal called "deep cleaned" coal and a middlings product with higher sulfur and ash content. Level 5

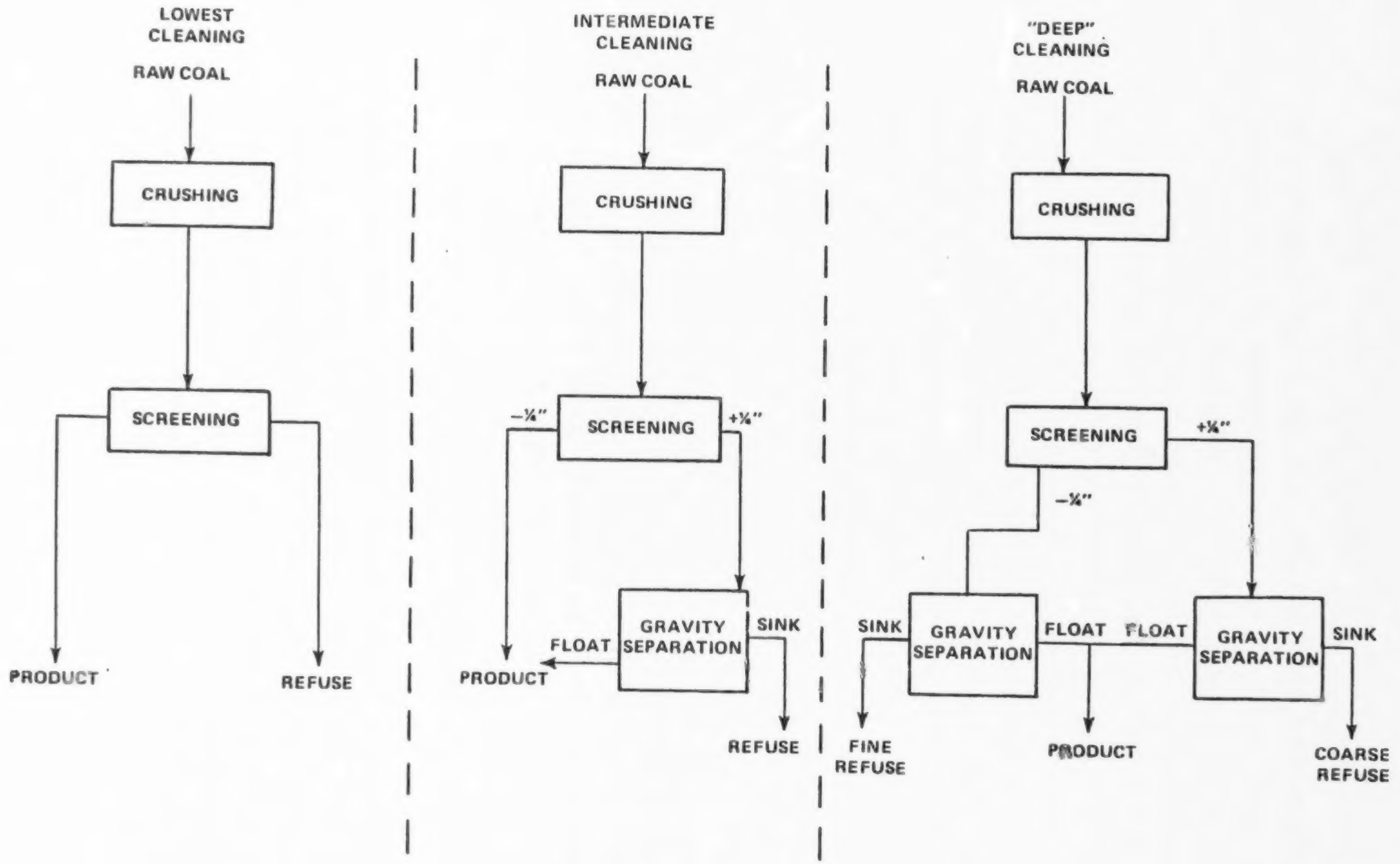

LOWEST CLEANING
RAW COAL
CRUSHING
SCREENING
PRODUCT
REFUSE
INTERMEDIATE CLEANING
RAW COAL
CRUSHING
SCREENING
−¼"
+¼"
GRAVITY SEPARATION
FLOAT
SINK
PRODUCT
REFUSE
"DEEP" CLEANING
RAW COAL
CRUSHING
SCREENING
+¼"
−¼"
SINK
GRAVITY SEPARATION
FLOAT
FLOAT
GRAVITY SEPARATION
SINK
FINE REFUSE
PRODUCT
COARSE REFUSE

Figure 4.5-1. Physical coal cleaning unit operations employed to achieve various levels of cleaning.

provides the most advanced state-of-the-art in physical coal cleaning with large reductions in pyrite and ash content and improvement of heat content at high yields. In addition, this system is flexible relative to the types of coal that can be processed. Variations in raw coal and product specifications can be handled by varying the heavy medium densities and careful control of coal sizes treated in various circuits.

Level 5 coal cleaning plants use the techniques and principles utilized in the first four levels, but combine them in unique ways to maximize mass and energy recovery. Major operations involved are crushing, screening or sizing, heavy media separation, secondary separation, dewatering and removal of fines from process water. The high efficiency of Level 5 is due to the repeated use of these operations to produce the desired products.[157]

4.5.2.1.2 Development status. There are currently over 460 physical coal cleaning plants in the U.S. In 1976 about 340 million tons of raw coal was processed by these plants. This represents 58 percent of the total 1976 U.S. coal production of 590 million tons. The majority of these plants were designed for ash removal rather than sulfur removal although many do take out 20-30 percent of the sulfur in the raw coal. The status of coal cleaning plants operated in 1976 is summarized in Table 4.5-1. Some plants use only one major cleaning process, while the majority use a series of cleaning processes. The capacity of individual plants varies widely from less than 200 metric tons per day to more than 25,000 metric tons per day.[159]

Levels 1 through 4 are currently in use in operating commercial plants which produce steam coal. There are examples of Level 5 systems at metallurgical coal plants where both a low sulfur, low ash metallurgical grade product and a middling (higher sulfur and ash content) combustion grade by-product are produced. All unit operations proposed for a Level 5 plant are presently used in commercial plants. However, the unit operations have not yet been combined to form a commercial Level 5 plant for producing steam coal.[160]

4.5.2.1.3 Applicability to industrial boilers. Firing of physically cleaned coal in industrial stoker-fired boilers is not expected to have a

TABLE 4.5-1. PHYSICAL COAL CLEANING PLANTS CATEGORIZED BY STATES FOR 1976.[158]

State	Estimated Total Coal Production, 1000 tons	Number of Coal-Cleaning Plants	Number of Plants for Which Capacity Data Reported	Total Daily Capacity of Reporting Plants, Tons	Estimated Annual Capacity of Reporting Plants,(a) 1000 tons	Number of Plants Using Various Cleaning Methods					
						Heavy Media	Jigs	Flotation Units	Air Tables	Washing Tables	Cyclones
Alabama	21,425	22	10	40,600	10,150	8	10	6	1	12	6
Arkansas	670	1	0	-	-	1	-	-	-	1	1
Colorado	8,160	2	0	-	-	2	-	1	-	-	-
Illinois	59,251	33	20	136,775	34,195	17	20	4	1	1	8
Indiana	24,922	7	6	42,000	10,500	2	5	1	-	1	3
Kansas	568	2	2	3,800	950	-	2	-	-	-	-
Kentucky	146,900	70	40	245,700	61,425	43	27	16	4	20	24
Maryland	2,792	1	0	-	-	-	-	-	-	-	1
Missouri	5,035	2	1	3,500	875	-	2	-	-	-	-
New Mexico	9,242	1	1	6,000	1,500	1	-	1	-	-	1
Ohio	44,582	18	13	102,750	25,690	6	11	-	1	2	5
Oklahoma	2,770	2	1	550	140	1	1	-	-	-	1
Pennsylvania (Anthracite)	5,090	24	14	13,000	3,250	21	4	4	-	3	2
Pennsylvania (Bituminous)	81,950	66	50	205,010	71,255	30	19	16	20	15	19
Tennessee	9,295	5	4	8,520	2,130	1	1	1	2	-	1
Utah	6,600	6	4	23,100	5,775	2	4	2	2	-	2
Virginia	36,500	42	29	143,550	35,090	26	15	9	8	15	11
Washington	3,700	2	1	20,000	5,000	1	1	-	-	-	-
West Virginia	110,000	152	113	577,375	144,345	104	55	59	12	55	59
Wyoming	23,595	1	1	600	150	-	-	-	1	-	-
Total	603,055	459	318	1,652,030	413,210	266	177	121	52	125	144

(a) The estimated annual-capacity values for the reporting plants were calculated from the daily-capacity values by assuming an average plant operation of 250 days per year (5 days per week for 50 weeks per year).

significant effect on boiler maintenance requirements. In industrial pulverized coal-fired boilers, firing of physically cleaned coal may reduce boiler maintenance costs.[161]

Physical cleaning of coal should improve the overall performance of a stoker-fired boiler provided the resultant coal size is acceptable for stoker firing (1-1/2" x 1/4" with minimal fines). Physical cleaning partially removes pyrites, ash, and other impurities, thus reducing both SO_2 and particulate emissions. As compared to raw coal, physically cleaned coal is easier to handle and feed, burns more uniformly with less chance for clinkering, and reduces ash disposal problems.[162] As an example, both a raw and the corresponding physically cleaned coal were fired in a steam plant spreader stoker boiler. When firing the raw coal, the boiler could operate only at about one half capacity. The high ash content of this coal resulted in nonuniform combustion caused by feeding problems, excessive ash buildup and clinker formation on the fuel bed. In contrast, the physically cleaned coal was fired at full capacity with no operational problems.[162]

4.5.2.2 Factors Affecting Performance. Sulfur reduction by physical cleaning varies depending upon the distribution of sulfur forms in the coal. There are three general forms of sulfur found in coal; organic, pyritic, and sulfate sulfur. Sulfate sulfur is present in the smallest amount (0.1 percent by weight or less). The sulfate sulfur is usually water soluble, originating from in-situ pyrite oxidation, and can be removed by washing the coal. Mineral sulfur occurs in either of the two dimorphous forms of iron disulfide (FeS_2) - pyrite or marcasite. The two minerals have the same chemical composition, but have different crystalline forms. Pyritic sulfur occurs as individual particles (0.1 micron to 25 cm. in diameter) distributed through the coal matrix. Pyrite is a dense mineral (4.5 g/cc) compared with bituminous coal (1.3 g/cc) and is quite water-insoluble thus the best physical means of removal is by specific gravity separation. The organic sulfur is chemically bonded to the organic carbon of the coal and cannot be removed unless the chemical bonds are broken. The amount of organic sulfur present defines the lowest limit to which a coal can be cleaned with respect to sulfur removal by physical methods. Physical cleaning typically can remove about 50 percent of the pyritic sulfur, although the actual removal depends on the washability of the coal, the unit processes employed and the density of the separating medium.[163]

A trade-off between product yield and purity exists for any one unit operation of a physical coal cleaning process. Product yield is defined as the ratio of the clean product heating value divided by the heating value of the raw coal and can vary from 0 to 1. Product purity refers to the amount of sulfur retained in the clean product - the lower the sulfur content, the higher the purity. One unit operation cannot achieve both performance goals -- either yield is maximized, or purity is maximized, or a compromise is made between yield and purity. This basic limitation on performance also applies to an entire plant if that plant only produces one clean coal product. However, the designer of a multiproduct plant may achieve both performance goals. As an example, one unit operation may be selected for maximizing product purity although the quantity of this clean product is relatively small. In this case, a fine fraction (28 x 0 mesh) may be produced with a pyritic sulfur content reduced by up to 90 percent, but with a yield of less than 50 percent. If the rejected portions are washed again at a relatively high specific gravity in another (sequential) unit operation, a "middling" product with somewhat higher pyritic sulfur content may be recovered with an overall recovery (between the two products) of the majority of the original heating value.[164]

The inherent design advantages of a multi-product plant do have special significance for industrial boilers. Since the coal quantities used by industrial boilers are a small fraction of the total coal demand, it might be quite attractive for a coal cleaning plant to produce a very clean product for new industrial boilers and a middling product suitable either for consumers subject to less stringent emission standards or for large consumers (i.e., utilities) with additional site-specific SO_2 controls.[165]

4.5.3 Oil Cleaning

Hydrotreating or hydrodesulfurization (HDS) processes are used to produce oil fuels substantially reduced in sulfur, nitrogen and ash content. They are chemical processes, which involve contact of the oil with a catalyst and hydrogen to convert much of the chemically-bonded sulfur and nitrogen to gaseous hydrogen sulfide (H_2S) and ammonia (NH_3). These gases are separated from the fuel and then collected.

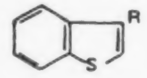
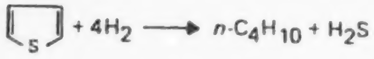
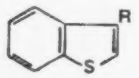
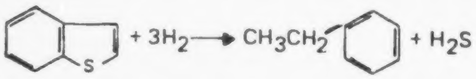
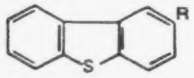
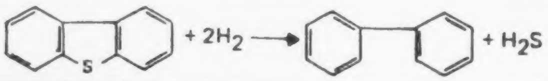
4.5.3.1 Process Description

4.5.3.1.1 System. In a typical hydrotreating process, oil to be treated is filtered to remove suspended material. The oil is then mixed with hydrogen, heated to 340 to 450°C (650° to 850°F), and passed over one or more catalytic reaction beds. The most widely-used catalysts are composites made up of cobalt oxide, molybdenum oxide, and alumina, where alumina is the support and the other agents are promoters.[166]

Numerous chemical reactions occur which lead to removal of most of the sulfur as H_2S. Table 4.5-2 illustrates some of the types of compounds and reactions involved.[167] In an HDS process, hydrogen also reacts with other species besides sulfur compounds. For example, nitrogen compounds break down to liberate ammonia from the oil. This is referred to as denitrogenation or denitrification. Nickel and vanadium in the oil, which are bound as organo-metal compounds, are also liberated by reaction with hydrogen. This is generally referred to as demetallization. Most of the liberated metals deposit (as the sulfide) on the catalyst surface or in its pores and slowly deactivate the catalyst. Other reactions which take place break up large complex molecules such as asphaltenes and lead to a reduction in carbon residue for the product oil.

Many companies are engaged in developing and using catalytic hydrotreating or hydrodesulfurization processes. All are similar in basic concept but vary in specifics such as the type of catalyst employed, the process conditions, and the process complexity. Figure 4.5-2 represents a simplified flow diagram of an HDS process currently being commercially marketed. Its basic elements are a feed filter, a heater, a single- stage catalytic reactor, a gas/liquid separator, a fractionating column, and a gas treatment section. This system is capable of producing fuel oil of approximately 1 percent sulfur from a feedstock such as atmospheric residual oil containing 2 percent sulfur. To produce a lower sulfur content product, additional catalytic reaction stages must be added. A system with two

Table 4.5-2. CHEMISTRY OF HYDRODESULFURIZATION REACTIONS IN PETROLEUM CRUDE OIL [167]

Name	Structure	Typical reaction
Thiols (mercaptans)	R–SH	$R{-}SH + H_2 \longrightarrow RH + H_2S$
Disulfides	R–S–S–R'	$R{-}S{-}S{-}R' + 3H_2 \longrightarrow RH + R'H + 2H_2S$
Sulfides	R–S–R'	$R{-}S{-}R' + 2H_2 \longrightarrow RH + R'H + H_2S$
Thiophenes		 S + 4H2 n-C4H10 + H2S
Benzothiophenes		 S + 3H2 CH3CH2 + H2S
Dibenzothiophenes		

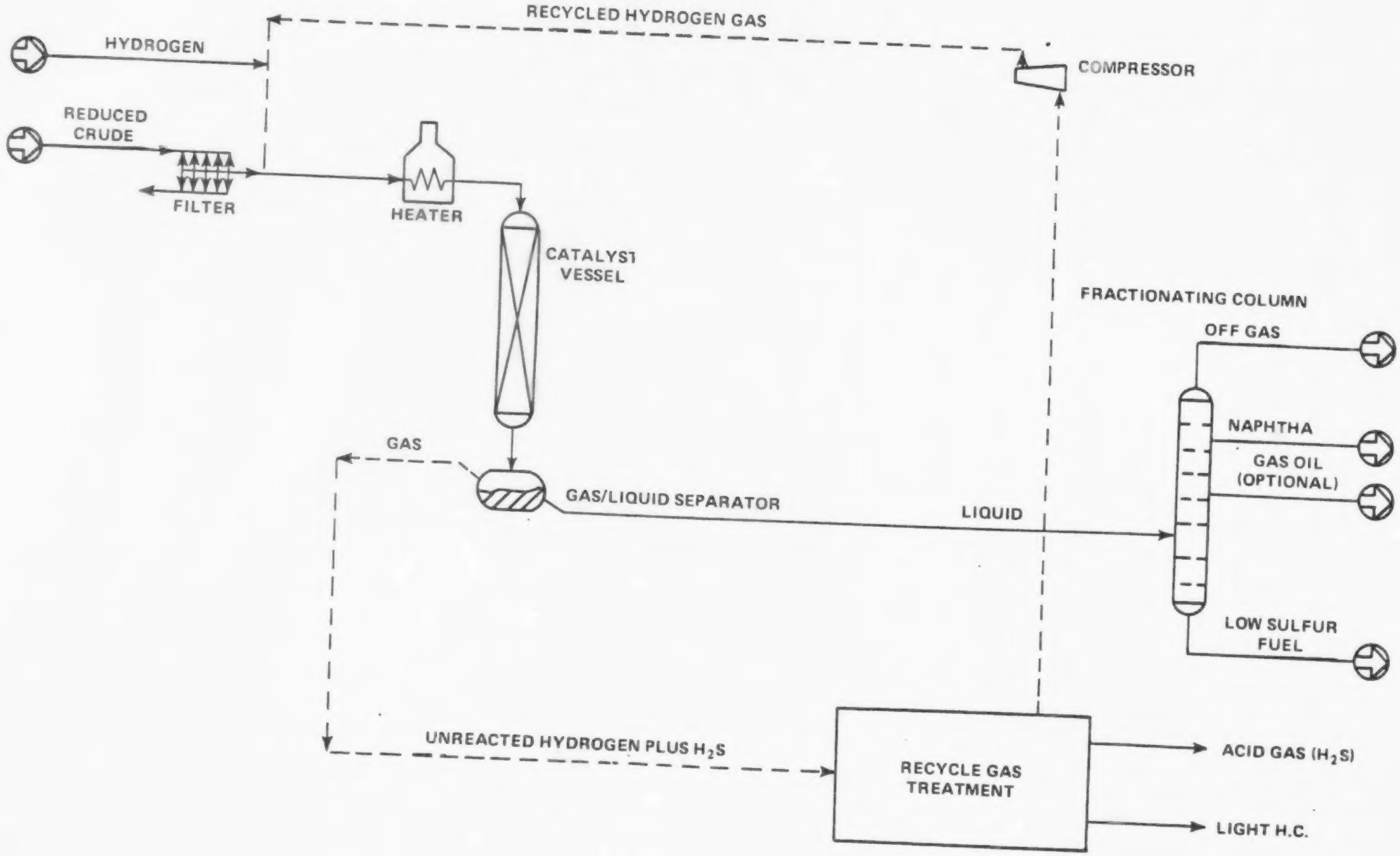

RECYCLED HYDROGEN GAS
HYDROGEN
COMPRESSOR
REDUCED CRUDE
FILTER
HEATER
CATALYST VESSEL
FRACTIONATING COLUMN
OFF GAS
GAS
NAPHTHA
GAS OIL (OPTIONAL)
GAS/LIQUID SEPARATOR
LIQUID
LOW SULFUR FUEL
UNREACTED HYDROGEN PLUS H_2S
RECYCLE GAS TREATMENT
ACID GAS (H_2S)
LIGHT H.C.

Figure 4.5-2. Basic HDS process.[168]

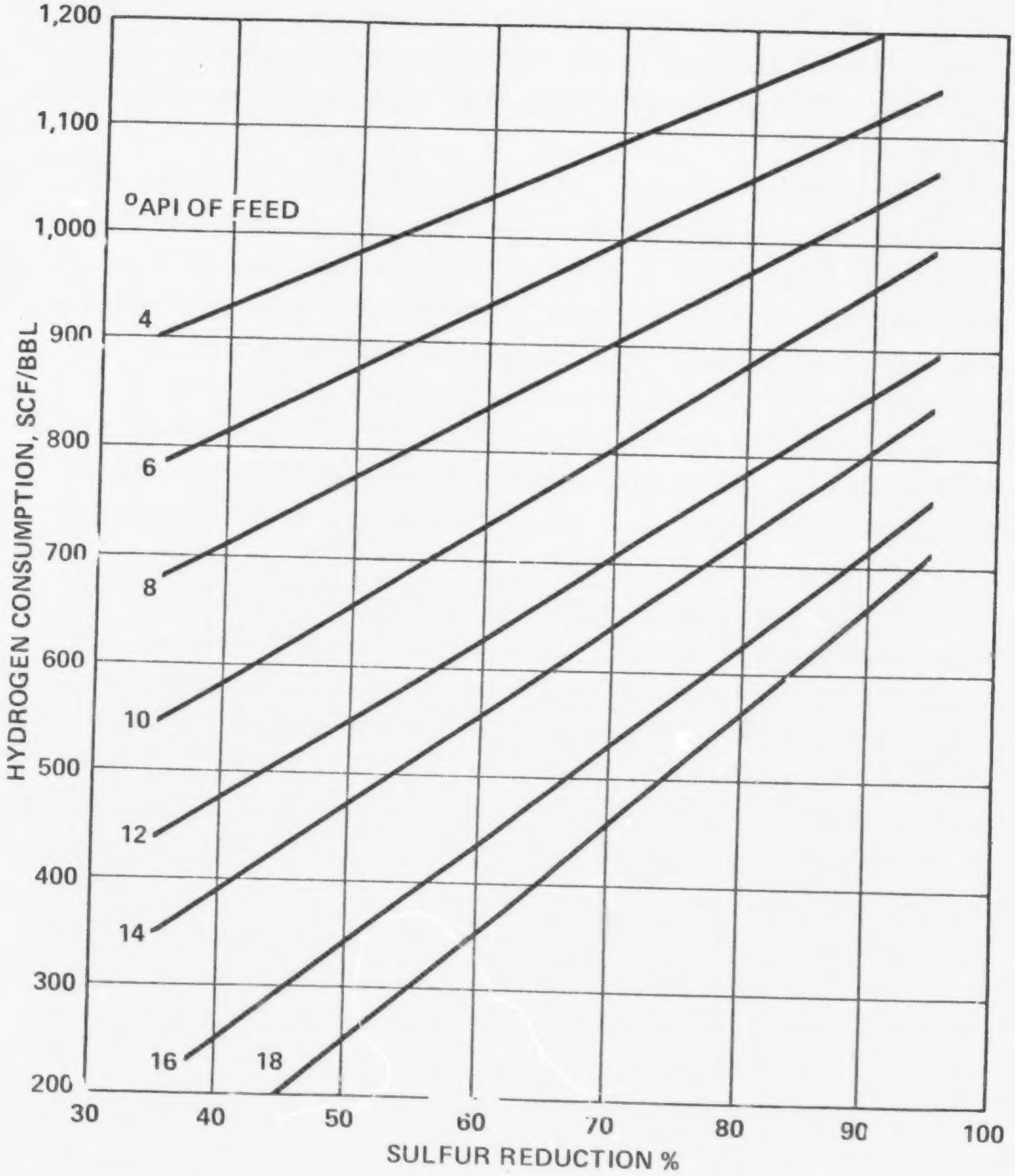
catalytic reaction stages can produce a fuel of approximately 0.3 percent sulfur content from a 2 percent sulfur feedstock. A more advanced process using three catalytic reactors can produce fuel oils with sulfur contents as low as 0.1 percent.[169]

4.5.3.1.2 Development status. Over 30 hydrotreating processes are actively in use, and more than 250 processes have been described in the patent literature since 1970.[170] Many of these processes have been in commercial existence for over 10 years. The particular process selected by a refinery depends on the existing or planned refinery products. In existing facilities, a fuel desulfurization process is usually chosen to minimize modification or retrofit and/or satisfy refinery product mix goals and feedstock purchase expectations. Hence, the desulfurization process selected depends on the required sulfur content of the product and the feedstock properties.

4.5.3.1.3 Applicability to industrial boilers. Like low sulfur fuel oil produced from naturally-occurring low sulfur crude, oil that has been treated by an HDS process is readily applicable to all boiler types and sizes that burn a similar grade of fuel. Use of this cleaned oil should not adversely affect the operation of the boiler. In fact, boiler performance may even be improved due to the potential for less corrosion and deposit formation in the boiler due to the chemical composition changes in the oil as a result of hydrotreating.[171]

4.5.3.2 Factors Affecting Performance. The composition of the feedstock to a hydrotreater strongly influences the amount of hydrogen and catalyst consumption in the process. Major feedstock variables are density (expressed as °API), sulfur content, and metals content.

Hydrogen consumption has been correlated with sulfur reduction for a variety of residual oil feeds. Figure 4.5-3 illustrates these results on feedstocks varying from 4 - 18° API gravity. It can be seen that to obtain 90 percent reduction in sulfur for a 19° API feedstock, about 0.1 Nm^3 of hydrogen are consumed per liter of oil processed (650 scf/barrel); whereas, a 4° API feed would require 0.2 Nm^3/liter (1200 scf/barrel).[173]



NOTE: 1. REDUCE BY 9% FOR FIXED-BED PROCESSES.
2. APPLY CORRECTION FOR HIGH-METALS FEEDS.

Figure 4.5-3. Hydrogen consumption in desulfurization of residual oil.172

As previously discussed, removal of metals by hydrotreating results in metals deposition on the catalyst surface or in the pores. This leads to deactivation of the catalyst, which can be overcome by a temperature or pressure increase to maintain acceptable processing rates. The increase in required severity of process conditions leads to more hydrocracking with a subsequent increase in hydrogen consumption.[174] Further complication from the metals content of the feed is a shortening of catalyst life. Even though some deactivation can be tolerated, the resultant increase in hydrogen consumption means the catalyst must be changed out more frequently.

The effect of metals is shown in Figure 4.5-4. This figure shows that for 90 percent sulfur removal from a 25 ppm metals content feedstock, about 27 barrels of oil can be processed per pound of catalyst; to achieve the same sulfur removal with a 100 ppm metals content feedstock, only 4.5 barrels can be procesed per pound of catalyst; a feedstock containing 300 ppm metals requires almost 1 pound of catalyst per barrel. Clearly, high metal feedstocks are a problem to the refiner. Therefore, many refiners are using a separate stage of lower cost catalyst material prior to the special hydrodesulfurization catalysts. These separate stages may be packed with a material such as alumina or clay, which collects the metals and "guards" the subsequent high activity catalyst. For this reason, some refiners refer to this stage as a "guard reactor" or "guard vessel".[176]

4.5.4 Low-Btu Gasification

Converting coal into a "clean" low-Btu gas with subsequent combustion in a boiler, reduces SO_2, NO_x, and particulate emissions (versus direct coal combustion) by removing the pollutant's precursors. With respect to particulate emissions, the coal ash content is physically separated from the gas when coal is gasified. Any entrained ash or coal particles are subsequently removed from the gas in hot cyclones and in the gas quenching and cooling steps. SO_2 emissions are reduced by removing sulfur species such as H_2S and COS from low-Btu gas prior to combustion. Nitrogen oxide emissions are reduced because low-Btu gas contains only small quantities of nitrogen compounds (NH_3 and cyanides) which are oxidized to NO_x (fuel N is

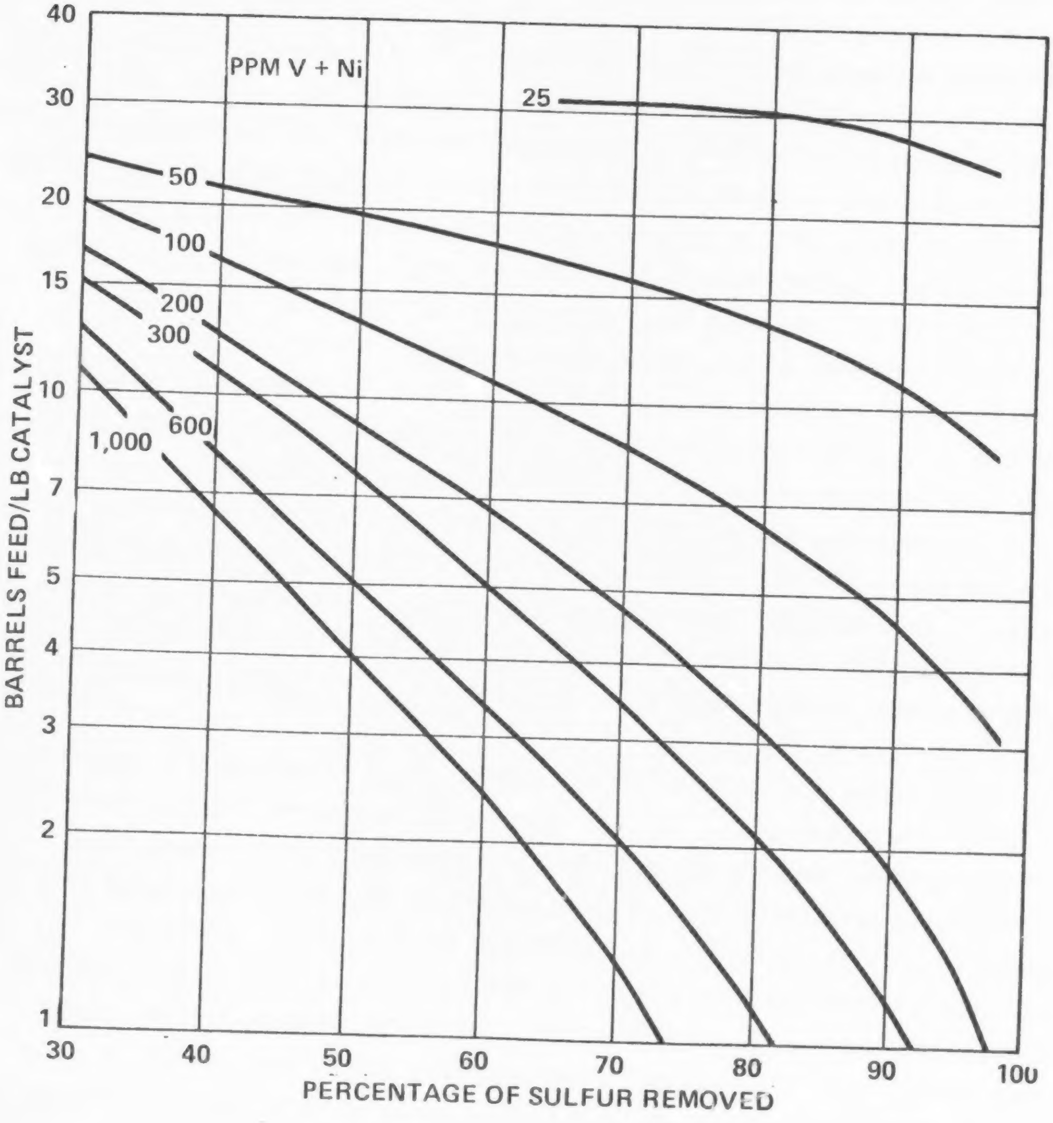


Figure 4.5-4. Effect of metals content on catalyst consumption.[175]

low compared to coal). Moreover, low-Btu gas burns with a low flame temperature which helps reduce the formation of NO_x by thermal fixation.[177]

4.5.4.1 Process Description

4.5.4.1.1 System. As shown by Figure 4.5-5 a low-Btu gasification system consists of three basic process steps: coal pretreatment, coal gasification, and product gas purification. Coal pretreatment is necessary to supply uniformly size coal to the gasifier. In the coal gasification step, pretreated coal is reacted with a steam/air mixture to produce a low-Btu gas with a heating value of apprxoiamtely 5.6 MJ/m^3 (150 Btu/scf). In the gas purification step, particulate matter, sulfur, and nitrogen compounds may be moved from the product gas. If not removed, the sulfur and nitrogen compounds would be oxidized to SO_2 and NO_x in the boiler and the particulate matter would erode the burner.

Close to 70 different low and medium Btu gasifier types have been used commercially in the past or are currently under development. Among the important characteristics which distinguish one gasifier from another are:

- Bed type,
- Operating conditions,
- Gasification media,
- Coal feeding technique,
- Ash removal process,
- Energy input, and
- Type of gas produced.

To produce a clean fuel, the critical parts of a coal gasification system are the gas purification and acid gas removal (AGR) operations. Removal of coal dust, ash, and tar aerosols entrained in the raw product gas leaving the gasifier is accomplished with cyclones, ESP's, and water or oil scrubbers. In the gas quenching and cooling section, tars and oils are condensed and particulates and other impurities, such as ammonia and cyanides, are scrubbed from the raw product gas.

Acid gases such as H_2S, COS, CS_2, mercaptans, and SO_2 are also removed with varying effectiveness from the raw product gas in the gas quenching and cooling section. Either low sulfur coal or AGR systems must be used to

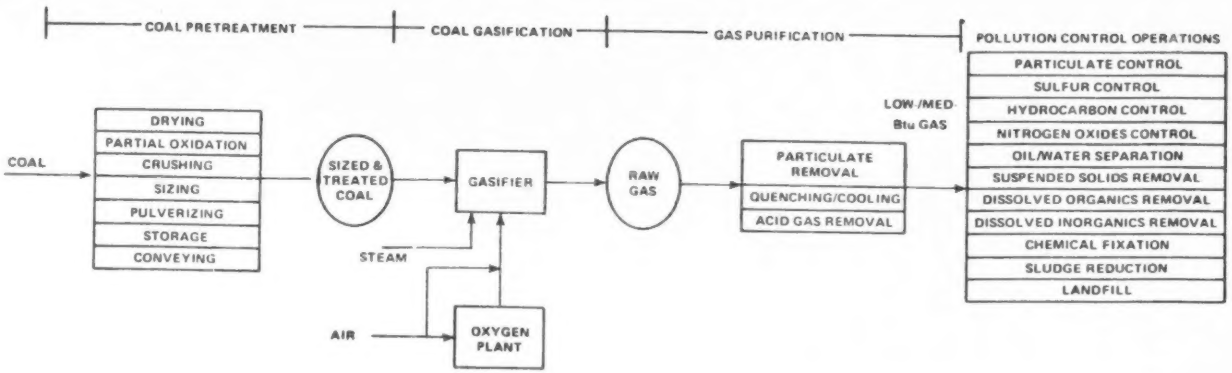

COAL PRETREATMENT
COAL GASIFICATION
GAS PURIFICATION
POLLUTION CONTROL OPERATIONS
COAL
DRYING
PARTIAL OXIDATION
CRUSHING
SIZING
PULVERIZING
STORAGE
CONVEYING
SIZED & TREATED COAL
STEAM
AIR
GASIFIER
OXYGEN PLANT
RAW GAS
PARTICULATE REMOVAL
QUENCHING/COOLING
ACID GAS REMOVAL
LOW-/MED-Btu GAS
PARTICULATE CONTROL
SULFUR CONTROL
HYDROCARBON CONTROL
NITROGEN OXIDES CONTROL
OIL/WATER SEPARATION
SUSPENDED SOLIDS REMOVAL
DISSOLVED ORGANICS REMOVAL
DISSOLVED INORGANICS REMOVAL
CHEMICAL FIXATION
SLUDGE REDUCTION
LANDFILL

Figure 4.5-5. Low-Btu coal gasification system process and pollution control modules[178]

avoid excessive sulfur emissions. Commercially available AGR techniques include physical and chemical solvent processes, direct conversion and catalytic conversion processes, and fixed-bed adsorption processes.[178] The specific process used depends on the major acid gas constituents.

4.5.4.1.2 Development status. LBG from coal has been produced both in the United States and overseas for many years. It is estimated that at one time there were some 11,000 coal gasifiers in use in the U.S. As the availability of natural gas increased, the number of operating gasification systems declined significantly. At the present time there are only a few coal gasifiers operating in the United States on a commercial basis,[179] and all of these are used to fuel process furnaces. Some of these furnaces have a heat transfer medium to transfer the energy from the combustion operation to the process, and, hence, they are similar in design to boilers. They also operate at combustion temperatures typical of industrial boilers, which indicates that low-Btu gas can be burned in industrial boilers. None of these systems incorporate an AGR process for gas cleanup. However, AGR processes are commercially available from a number of process licensors and vendors.

4.5.4.1.3 Applicability to industrial boilers. Low-Btu gasification systems are applicable to any size industrial boiler. For an 8.8 MW (30×10^6 Btu/hr) industrial boiler, one 3 m (10 ft) diameter Wellman-Galusha gasifier is required. For larger boilers, multiple gasifiers would be used (ten 3 m diameter gasifiers are required for a boiler with a thermal input of 117.2 MW or 400×10^6 Btu/hr). All of the low-Btu gasification systems examined in the individual technology assessment report for synthetic fuels are sources of gaseous emissions, liquid discharges, and solid wastes. However, with suitable precautions there do not appear to be any uncontrollable adverse environmental impacts associated with the production and use of low-Btu gas.

The use of coal-derived low-Btu gas in new industrial gas-fired boilers has several advantages over the use of coal in direct coal-fired boilers. First, a gas-fired boiler is a much simpler piece of equipment to operate than a coal-fired boiler. There is no need for ash handling equipment and the only fuel handling equipment required is piping. However, ash handling equipment will be required at the gasifier location. Second, due to the less complex nature of gas-fired boilers, maintenance requirements will be less than for coal-fired boilers.[180]

On the other hand, the production and use of coal-derived gases at an industrial site can have adverse impacts. The primary concerns are the reliability/operability of the gasification system and how that affects the operability of the boiler. In order to minimize adverse impacts, installation of spare capacity or sparing of key process units in the gasification system may be required. Another alternative would be to provide a backup fuel source (such as distillate fuel oil) for the boiler. The incorporation of either of these options into a gasification/steam generation system design must be done on a case by case basis, taking into consideration the particular requirements of the system. In addition, in the selection and design of the boiler, consideration must be given to the different combustion characteristics (e.g., heat release rate and flame temperatures) of coal-derived gas versus natural gas.[180]

4.5.4.2 Factors Affecting Performance. The performance of LBG as an emission control technique for industrial boilers depends on the performance of the gas purification system operation. More specifically, it depends on the performance of the acid gas removal unit in removing H_2S and organic sulfur compounds (predominantly COS) from the product gas. The demonstrated acid gas removal processes are capable of removing over 90 percent of the sulfur species from the raw gases.[181]

SO_2 emissions can be predicted accurately from the producer gas analysis, which is available from several gasifier/acid gas removal system combinations. An upper limit on particulate emissions can also be predicted, based on the particulate content of the cleaned gas and experience with gas-fired boilers. Particulate emissions are estimated to approach those for natural gas-fired boilers. NO_x emission data for specific coal and gasifier types which are necessary to accurately predict NO_x emission levels from industrial boilers firing low-Btu gas are not available.

4.5.5 Solvent Refined Coal

The Solvent Refined Coal (SRC) process is a fuel pretreatment process designed to produce clean solid (SRC-I) and liquid (SRC-II) fuels. Both the SRC-I and SRC-II processes use a noncatalytic hydrogenation step in which coal is partially dissolved in a hydrogen-rich solvent to produce a fuel substantially reduced in sulfur and ash content compared to the raw coal. Fuel nitrogen content may also be reduced.

4.5.5.1 Process Description

4.5.5.1.1 System. The two SRC processes are shown schematically in Figure 4.5-6. In the SRC-I process, slurried coal is liquified and the product is separated from the unreacted residue by filtration. Recycled solvent for coal-slurry preparation is recovered from the product mixture by distillation. The rest of the liquid product is solidified to produce a boiler fuel. In the SRC-II process, more hydrogen (almost double the amount required in the SRC-I process) is added to the coal in the liquefaction reactor. The unreacted solids are separated from the product by vacuum distillation, and a fraction of the liquid product is recycled for slurry preparation. The product liquids may be hydroprocessed for further upgrading, depending on the product quality desired.

4.5.5.1.2 Development status. Systems to produce SRC fuels are in advanced stages of development and could be commercially available in the late 1980's. Both solid and liquid boiler fuels are currently being produced in DOE sponsored SRC-I and SRC-II pilot plants.[183] Table 4.5-3 presents a comparison of the status of development of the two SRC processes.

4.5.5.1.3 Applicability to industrial boilers. Preliminary results from SRC-I handling and burning tests indicate that some industrial boiler modifications may be required for the operation of the fuel handling and storage equipment, pulverizers, burners, and the combustion process if SRC fuels are used.[185] In pulverized coal-fired boilers, for example, pulverizer temperatures must be lowered to prevent the SRC-I fuel from melting during pulverization. Pulverizer temperatures can be lowered by reducing the amount of air that the pulverizer receives from the air preheater.[186] In addition, the solid fuel produced by the SRC-I process is

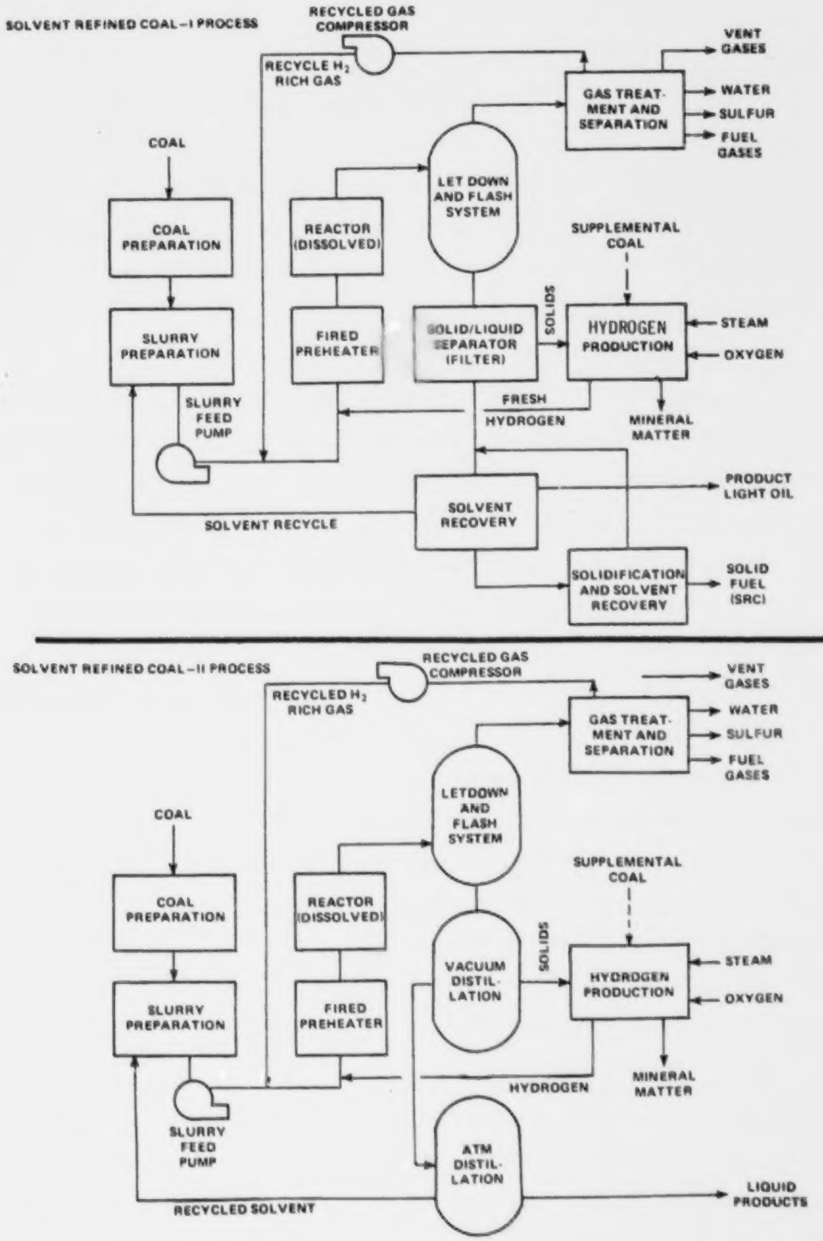

SOLVENT REFINED COAL-I PROCESS
RECYCLED GAS COMPRESSOR
RECYCLE H_2 RICH GAS
VENT GASES
GAS TREATMENT AND SEPARATION
WATER
SULFUR
FUEL GASES
COAL
LET DOWN AND FLASH SYSTEM
COAL PREPARATION
REACTOR (DISSOLVED)
SUPPLEMENTAL COAL
SOLIDS
SLURRY PREPARATION
FIRED PREHEATER
SOLID/LIQUID SEPARATOR (FILTER)
HYDROGEN PRODUCTION
STEAM
OXYGEN
SLURRY FEED PUMP
FRESH HYDROGEN
MINERAL MATTER
PRODUCT LIGHT OIL
SOLVENT RECOVERY
SOLVENT RECYCLE
SOLIDIFICATION AND SOLVENT RECOVERY
SOLID FUEL (SRC)
SOLVENT REFINED COAL-II PROCESS
RECYCLED GAS COMPRESSOR
RECYCLED H_2 RICH GAS
VENT GASES
GAS TREATMENT AND SEPARATION
WATER
SULFUR
FUEL GASES
COAL
LETDOWN AND FLASH SYSTEM
SUPPLEMENTAL COAL
COAL PREPARATION
REACTOR (DISSOLVED)
SOLIDS
VACUUM DISTILLATION
HYDROGEN PRODUCTION
STEAM
OXYGEN
SLURRY PREPARATION
FIRED PREHEATER
HYDROGEN
MINERAL MATTER
SLURRY FEED PUMP
ATM DISTILLATION
LIQUID PRODUCTS
RECYCLED SOLVENT

Figure 4.5-6. Flow diagram of the SRC-I and SRC-II liquefaction processes.[182]

Table 4.5-3. GENERAL COMPARISON AND RELATIVE TECHNICAL STATUS OF THE SRC-I AND SRC-II LIQUEFACTION PROCESSES [184]

Technical Status	SRC-I	SRC-II
Pilot unit Scale of Operations (metric tons/day, coal)	0.9	0.9
Size of Pilot Plant (metric tons/day, coal)	a) 45 b) 5.5	27.3
Pilot Plant began Operation	a) Late 1974 b) Mid-1976	Mid-1977
Fuel Types	Refined coal (solid fuel)	Distillate oil
Coal Feed	Eastern Western	Eastern (high pyrites only)
General Comparisons		
Fuel Flexibility	Developed to produce substitute solid boiler fuel only	Poor
Reactor Operating Severity	Moderate	High
Process Scale-up Risk	Moderate	High
Number of New Components and Design of Commercial Equipment	High	High
Reactor Complexity	Moderate	Moderate
Fuel Utilization, Combustion		
Raw Product, Stability, Compatibility	Moderate	Poor
Combustion Experience	Moderate	Limited

not applicable to all industrial coal-fired stoker boilers. SRC-I solids have a low melting point (approximately 615 K or 310°F) and would melt on the grate of current fixed-bed stoker boilers before they are combusted.[187]

Fuels from the SRC-II process may be used to replace residual fuel oil as an industrial boiler fuel with minor modificatons in the combustion process.[188]

4.5.5.2 Factors Affecting Performance. The primary operating variables which could affect the conversion of sulfur and nitrogen in the raw coal to hydrogen sulfide and ammonia for removal from the fuel are:

- Characteristics of the raw coal,
- Process operating variables,
- Hydrogen consumption,
- Reactor space velocity, temperature, and pressure, and
- The degree of hydroprocessing of the raw product fuel.

The higher the sulfur and nitrogen content of the coal processed, the greater the hydrogen consumption will be. Nitrogen removal is more difficult than sulfur removal because the reaction between nitrogen and hydrogen does not take place easily. Nitrogen removal from the feed coal ranges from approximately zero to 40 percent with about half of the nitrogen removed going into the production of ammonia.[189]

Reactor space velocity, temperature, and pressure all affect hydrogen consumption. An increase in reactor temperature and pressure results in increased reaction rates with an increase in hydrogen consumption. An increase in residence time (decrease in space velocity) also increases the consumption of hydrogen. Since hydrogen consumption is influenced by all these variables, it is used as an indicator of the sulfur and nitrogen removal.[190]

Reactor temperature and residence time have greater effects on sulfur removal than reactor pressure.[190] At low temperatures, the relationship between sulfur removal and hydrogen consumption is approximately linear. However, as the temperature is increased, more sulfur is removed but at a lower rate. Sulfur removal can also be increased by increasing reactor pressure and residence time.

An increase in reactor temperature also increases hydrogen consumption to react with nitrogen; however, nitrogen removal at higher temperatures does not significantly change.[190] It appears that the effect of reactor pressure changes on hydrogen consumption for nitrogen removal is small, on the order of 0.1 percent nitrogen content change for a change in pressure from 8.86 to 10.49 MPa (1280 to 1520 psi).

Raw coal-derived liquid fuels differ from petroleum-derived fuels in that they are very aromatic and, as such, are hydrogen deficient. Hydroprocessing can be used to increase the hydrogen content of coal-derived fuels by catalytically reacting hydrogen with the fuel. Hydrogenation also further decreases the sulfur and nitrogen content of the coal-derived liquid fuel produced. The hydroprocessing variables that affect sulfur and nitrogen removal from coal-derived liquids are catalyst type and hydrogen consumption.[191]

There is limited storage and combustion data on coal liquefaction products from either of the two SRC processes. The Ft. Lewis, Washington, SRI-I pilot plant with a capacity of 45 metric tons per day, produced a 2725 metric ton sample of solid SRC-I fuel for combustion testing at the 22 MW_e Plant Mitchell power station of the Georgia Power Company. The combustion tests were performed in the second quarter of 1977.[192] Small-scale tests on home heating units and industrial boilers, and some limited laboratory tests have been performed with SRC-II liquid fuels.[192]

4.5.6 Oil/Water Emulsions

Oil/water emulsions can be fired in distillate and residual oil-fired boilers to enhance the atomization of the fuel and obtain improved combustion. As a result of improved combustion, the firing of an oil/water emulsion in an industrial boiler can result in decreased particulate emissions, and, in some cases, decreased NO_x emissions.

4.5.6.1 Principle of Operation. The oil/water emulsion process is based upon the firing of a stable emulsion in a conventional oil-fired boiler. Emulsion preparation equipment commercially available uses ultrasonics or mechanical means to produce stable emulsions. Surfactants are required to produce a stable emulsion with distillate oil; whereas, residual oil, because it typically contains natural surfactants, will form a stable emulsion without surfactant addition.[193,194]

When firing an oil/water emulsion, each fuel droplet contains one or more small droplets of water. During combustion the internal water droplets vaporize, causing mini-explosions of the fuel droplets, leading to a much finer atomization and a very thorough mixing of air and fuel. This allows complete combustion with much less excess air and results in a dramatic reduction in soot production. Use of less excess air means that less heat is carried out the stack by the exhaust gases and the reduction of soot formation keeps the boiler heat transfer surfaces clean. Thus, boiler efficiency is improved.[195,196]

Improved combustion conditions result in less unburned carbon being emitted from the boiler with a resulting decrease in particulate emissions. Some tests have, however, shown that particulate emissions from firing an emulsion may have a smaller size distribution resulting in increased visible emissions although the mass emissions decrease.[197] In addition to reductions in particulate emissions, use of oil/water emulsion technology has been reported to lower NO_x emissions for distillate oil firing due to the lower excess air used and the reduced combustion temperatures which result.[198] However, no significant reduction was observed for residual oil emulsions due to the high nitrogen content of the residual oil fuel tested.[199]

4.5.6.1.2 Development status. Oil/water emulsifiers have been marketed commercially in the United States and Europe since the early 1970's.[200] Emulsifiers sold to date have been primarily used for the purpose of increasing boiler efficiencies through improved combustion. Environmental benefits have, apparently, not been a major factor in sales of emulsification systems, and consequently, actual performance data concerning emission reductions achieved by this technology are not available.

4.5.6.1.3 Applicability to industrial boilers. Oil/water emulsion systems are generally applicable to industrial boilers burning either distillate oil or residual oil. Applications to date have been retrofits for the primary purpose of improving the combustion efficiency of older boilers. Improved combustion conditions typical of new boilers, with improved burner designs and instrumentation, will result in essentially the same benefits that emulsion firing has been shown to provide. Consequently, this technology will probably continue to have as its major application the improvement of the performance of existing installations.

4.6 COAL/ALKALI COMBUSTION TECHNIQUES FOR SO_2 CONTROL

Both combustion of coal/alkali fuel mixtures or coal in a bed of alkaline sorbent are being developed as alternatives to post-combustion SO_2 control. Two of the most promising alternatives are combustion of coal/limestone fuel mixtures and combustion of coal in a fluidized bed of limestone. With these combustion techniques, fuel sulfur is converted to SO_2 which reacts with calcium oxide and excess oxygen in the fuel bed according to the following overall reaction.

$$SO_2\ (g) + CaO\ (s) + \tfrac{1}{2}\ O_2\ (g) \rightarrow CaSO_4\ (s)$$

The CaO is produced by a rapid calcining of calcium carbonate (limestone) in the fuel bed using the heat of combustion. Most of the calcium sulfate formed stays in the fuel bed and is removed from the system along with the bottom ash. Some $CaSO_4$ may become entrained in the flue gas and subsequently be collected in a downstream particulate control device.

This section describes two methods that may be used to burn coal/alkali fuel mixtures for SO_2 control. Fluidized bed combustion (FBC) is discussed first followed by coal/limestone pellet (CLP) combustion. It should be noted that CLP technology is still in the developmental stage and any information presented should be considered as preliminary and subject to change. FBC technology has been used on a limited basis with its use expected to increase in the future.

Development of another process involving combustion of coal/limestone fuel mixtures is currently being funded by EPA, with future plans for a joint EPA/DOE development program being considered. In this process, a pulverized mixture of coal and limestone is fired in a low-NO_x burner to reduce SO_2 and NO_x emissions (relative to the combustion of coal in a conventional burner.) However, development of this process had not progressed beyond bench scale at the time of this report.

4.6.1 Fluidized Bed Combustion for SO_2 and NO_x Control

Fluidized bed combustion (FBC) is a boiler design option which, because of the nature of its operation, results in lower SO_2 and NO_x emissions. Because of its SO_2 and NO_x emission reduction potential, FBC is discussed here as a pollution control technique rather than as a boiler type in Chapter 3. FBC technology offers a variety of advantages over conventional boiler designs, including SO_2 emission reduction without use of FGD systems, smaller more compact boilers, and flexibility in fuel use.

Although both pressurized and atmospheric fluidized-bed designs are currently being developed, it appears that atmospheric fluidized bed combustion (AFBC) will dominate the FBC market for industrial boiler applications in the near future. Apparently, the additional complexity of the pressurized designs (and associated cost) is not offset by increased performance in industrial boiler applications. Pressurized designs may, however, prove to be economical in utility, co-generation, and combined cycle power plants.[201] In the following discussion, only AFBC designs will be considered.

4.6.1.1 Process Description

4.6.1.1.1 System. A simplified schematic diagram of an AFBC boiler is presented in Figure 4.6-1. The unit is comprised of a bed of sorbent (or inert material) which is suspended or "fluidized" by a stream of air at 0.3 to 4.6 m/sec (1 to 15 ft/sec).

Coal is injected into this bed and burned. A sorbent (usually limestone or dolomite) is also injected to react with the SO_2 formed upon combustion. The gas velocity is set so that the bed particles are suspended and move about in random motion. Boiler tubes submerged in the bed remove heat at a high rate to maintain bed temperatures in the range of 760° to 870°C (1400° to 1600°F).[203]

Particulate matter emitted from the boiler passes to a primary cyclone where 80 to 90 percent of the larger carbon containing particles are removed. This collected material can be recirculated back to the FBC unit,

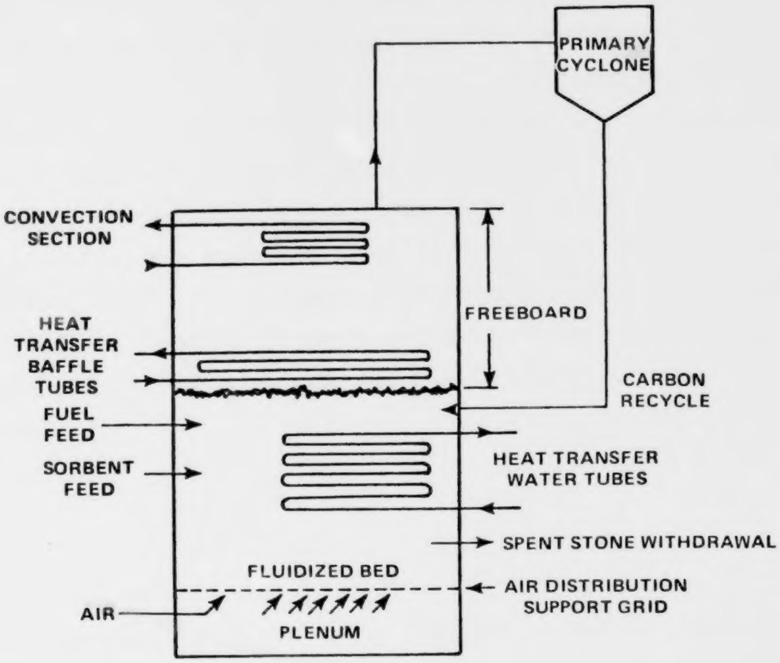

PRIMARY CYCLONE
CONVECTION SECTION
FREEBOARD
HEAT TRANSFER BAFFLE TUBES
CARBON RECYCLE
FUEL FEED
SORBENT FEED
HEAT TRANSFER WATER TUBES
SPENT STONE WITHDRAWAL
FLUIDIZED BED
AIR DISTRIBUTION SUPPORT GRID
AIR
PLENUM

Figure 4.6-1. Typical industrial FBC boiler.[202]

fed to a carbon burnup cell (CBC) to maximize combustion efficiency, or disposed of. A carbon burnup cell is a separate FBC reactor which is operated at higher temperatures [1090°C (2000°F)] than the main FBC to achieve maximum carbon utilization.[203]

In addition to the cyclones normally incorporated in an atmospheric FBC design, additional particulate control equipment such as "hot-side" or "cold-side" ESPs or fabric filters (see Section 4.1) may be used to further reduce particulate emissions.

FBC technology can reduce SO_2 emissions by up to 90 percent or more depending upon the rate of sorbent addition to the bed and the FBC design and operating conditions. Nitrogen oxide (NO_x) emissions from FBC are inherently lower than uncontrolled emissions from conventional combustion. Combustion temperature is considerably lower in FBC (815° to 930°C [1500° to 1700°F]) than conventional combustion (1500°C [2700°F]). The lower FBC combustion temperature results in lower NO_x emissions due to reduced fixation of atmospheric nitrogen. Formation of NO_x at the lower temperatures is primarily due to the oxidation of fuel nitrogen.[204]

$$2N\ (\text{fuel}) + O_2 \rightarrow 2NO$$

The NO is formed rapidly as the coal burns and is thought to be reduced in the presence of carbon monoxide and other products of incomplete combustion, by a reaction such as the following:[204]

$$2CO + 2NO \rightarrow 2CO_2 + N_2$$

Some combustor design and operating conditions tend to increase NO_x emissions. For example, increasing bed temperature, increasing excess air, decreasing gas residence time, and possibly increasing fuel nitrogen content can all contribute to increased NO_x emissions. However, the influence of these variables on NO_x emissions has not been quantified or correlated; and the mechanisms of NO_x formation and decomposition in FBC are not well understood. Hence, it is not possible to design FBC's for low NO_x emissions with the same reliability possible for SO_2.[205]

4.6.1.1.2 Developmental status. Development of coal-fired FBC industrial boilers is continuing on several fronts. Much of the work is being conducted with funding and guidance from the U.S. Department of Energy (DOE) as part of the National Energy Research, Development, and Demonstration Program. Recently the State of Ohio has supported FBC development. In addition, several vendors now offer commercial FBC industrial boilers independent of government funding. Finally, industrial boiler FBC development is being supported through utility FBC development work: The Electric Power Research Institute (EPRI) is actively involved in this program.

DOE lists four major demonstration FBC boilers currently operating or under construction.[206] The installation at Georgetown University has been operating since mid-1979. This unit is a two-bed design with a total capacity of 44,840 kg/hr (100,000 lb/hr) of saturated steam. Another major demonstration project is the 22,420 kg/hr (50,000 lb/hr) boiler at the Great Lakes Training Center in Illinois. This unit is currently scheduled for start-up in early 1981. The remaining DOE demonstration projects are part of an investigation into the use of anthracite culm (mine tailings) in industrial boilers. A 8,970 kg/hr (20,000 lb/hr) boiler is under construction in Paxinos, Pennsylvania and will supply a paper reprocessing plant. Finally, a larger 44,840 kg/hr (100,000 lb/hr) boiler is planned to supply the City of Wilkes-Barre, Pennsylvania with steam for heating and air conditioning.

At least three manufacturers now offer FBC industrial boilers on a commercial basis. Units as large as 50,000 lb/hr are available as package boiler units. The largest of the industrial FBC boiler manufacturers reports 14 sales of coal-fired industrial boilers, 10 of which will burn pure coal with the remaining four burning mixtures of coal and other fuels.[207]

Despite the availability of commercial units, FBC is still an emerging technology. Long term data on the performance of FBC units is lacking.

Future work is currently being directed toward the confirmation of long-term SO_x removal efficiency in large scale units. Documentation of the influence of gas phase residence time and sorbent particle size on SO_2 removal are other major areas of research. Other investigations are required to assess limestone characteristics and availability as well as alternative sorbents.[208]

Experimental work is continuing in an effort to gain a better understanding of NO_x formation/reduction mechanisms in FBC, and of the correlation between emissions and the key FBC design/operating conditions which can influence emissions. The goal of these studies is to provide the capability to better predict and control NO_x emissions through adjustment of standard design/operating conditions. Also, several investigators are beginning to address combustion modifications, deliberately aimed at reducing NO_x emissions from FBC, such as staged combustion, flue gas recirculation, ammonia/urea injection, and stacked beds. It is necessary to define the effects of such combustion modification techniques, not only on NO_x emissions, but on other system parameters, such as combustion efficiency and materials corrosion and the potential increase of SO_2 particulate emissions.[209]

4.6.1.1.3 Applicability to industrial boilers. Fluidized bed combustion can be used in place of practically any type of industrial boiler (stoker, pulverized coal, gas/oil). FBCs can be used for saturated/unsaturated steam, process heating (water, air, crude oil), and direct/indirect heating applications.

In the industrial boiler capacity size range of less than 73.3 MW (250×10^6 Btu/hr) it is expected that most, if not all, FBC units will operate at atmospheric pressure with a once-through sorbent processing scheme. Most industrial FBC boiler users probably will not have sufficient need for onsite electric power generation to justify the additional capital and operating costs and operational complexity associated with pressurized FBC systems. A similar argument of economics, operational complexity, and technological demonstration holds for sorbent regeneration systems. It is expected that the typical industrial user will select a once-through sorbent operating scheme, due to its demonstrated simplicity and lower costs, at least for first generation FBC installations.[210]

The concensus of opinion indicates that widespread application of coal-fired FBC industrial boilers will be limited to systems greater than 15 to 30 MW (50 to 100 x 10^6 Btu/hr) thermal input. This is due primarily to the high cost of related coal and ash handling equipment for smaller units. However, there does not appear to be any lower capacity technical limit to coal firing with FBC technology.[211]

Fuel flexibility is an important advantage of FBC use in the industrial sector due to the incentive to burn industrial byproducts and low-grade, high sulfur fuels not easily burned in conventional boilers. FBC boilers have multifuel capability and can burn all ranges of coal, oil, and gas and some industrial wastes.

FBC industrial boilers produce higher amounts of solid waste, relative to conventional cumbustion, since spent sorbent as well as ash must be disposed of. It is possible that waste disposal requirements for FBC may limit its use in areas with severe solid disposal limitations. For most installations, solid disposal will not be a major factor influencing the use of FBC boilers.

4.6.1.2 Factors Affecting Performance.

SO_2 Control. Of the factors which affect SO_2 emission control, the calcium to sulfur molar feed ratio (Ca/S) has the greatest impact. As the calcium content of the bed is increased, greater SO_2 removal is achieved. Westinghouse Research and Development Center has developed a model which projects sorbent requirements to attain certain levels of SO_2 removal efficiency. Figure 4.6-2 illustrates the rapid increase in sulfur retention with increasing Ca/S based on the model. For sorbents with a particle size of approximately 500 μm, the relationship is nearly linear below about 75 percent SO_2 removal. Above this level, sulfur retention approaches 100 percent asymptotically. However, further data from larger systems and for high levels of SO_2 removal are required to fully support the model projections.[213]

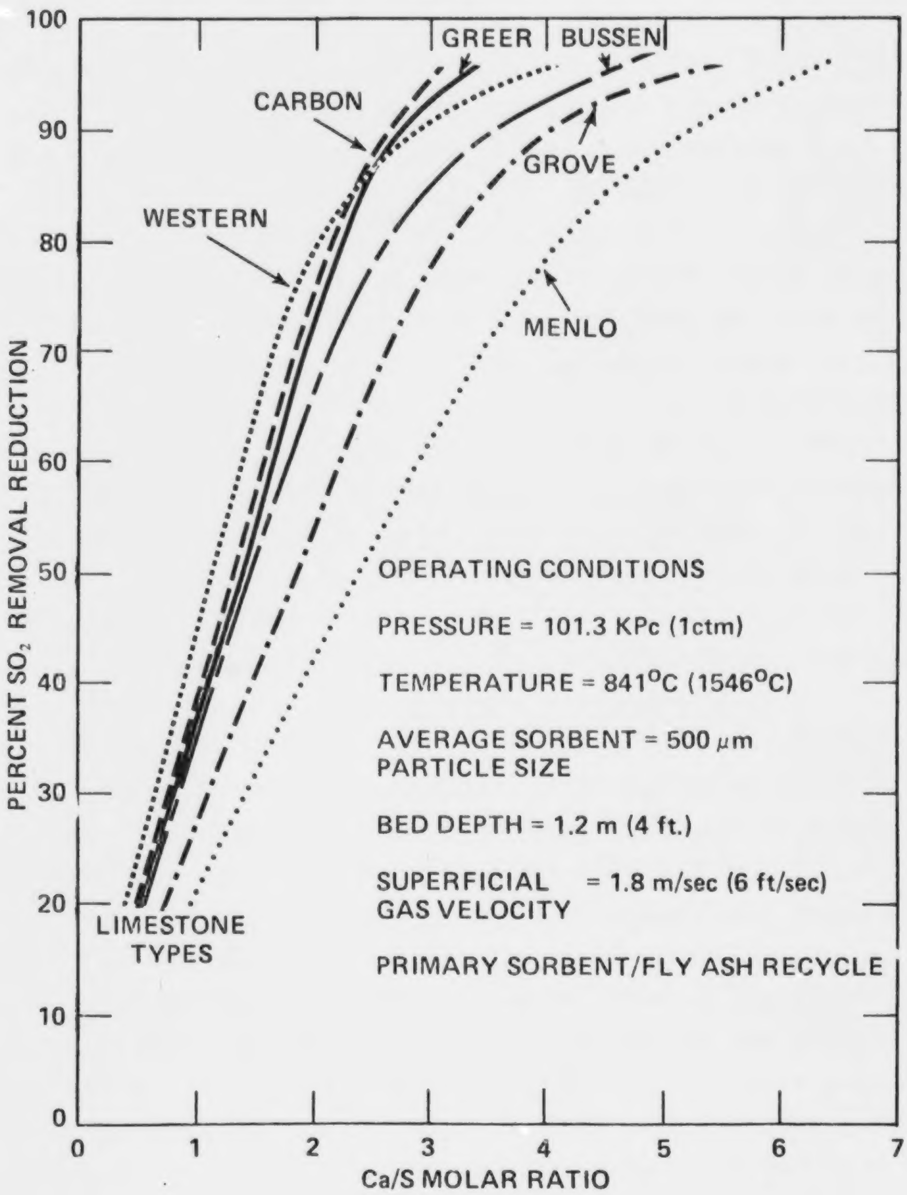


Figure 4.6-2. Projected desulfurization performance of FBC based upon a model developed by Westinghouse.[212]

Sorbent particle size is also an important factor influencing SO_2 reduction. As the particle size of a given sorbent is decreased, the calcium utilization is increased. Thus, with the same Ca/S molar feed ratio, the SO_2 reduction efficiency can be increased significantly by decreasing the sorbent particle size. The increased reactivity of smaller sorbent particles is due to their greater surface area.[214]

A third major factor which affects the sulfur removal efficiency of the system is the time the gas phase remains in the bed and is defined as the ratio of the expanded bed height to the superficial gas velocity. Figure 4.6-3 illustrates the calculated relationship between gas phase residence time and Ca/S molar feed ratio required to achieve 90 percent SO_2 removal, at various particle sizes for two types of limestone. As gas residence time is increased, the required calcium to sulfur molar feed ratio decreases. Figure 4.6-3 also indicates that there is a critical gas residence time (0.6 to 0.7 sec) below which sulfur retention efficiency is severely reduced.[216]

These three control factors are interrelated and can be varied to obtain the optimum SO_2 removal efficiency. A trade-off must be made among these factors in designing the optimum system.[216] There are, however, factors other than these which affect emission control. Overbed feeding is technically simpler than underbed feeding, but solid and gas residence time may be less than desirable. SO_2 released above the bed could be captured with reduced efficiency and sorbent may be entrained in the flue gas before it has a chance to react.[217]

The temperature within the bed may have a direct effect on the efficiency of the reaction between sulfur dioxide and calcium oxide. Several investigators have shown that optimum temperatures for calcium use are between 760° and 870°C (1400° and 1600°F), depending upon the coal and sorbent used. Figure 4.6-4 shows pilot scale results comparing sulfur retention versus temperature for two coals. The lower temperature limit is determined by the temperature at which calcination occurs; that is, $CaCO_3$ releases CO_2, forming CaO, the reactive form of the sorbent. Below 760°C (1400°F) calcination is not complete. The lower sulfur retention observed

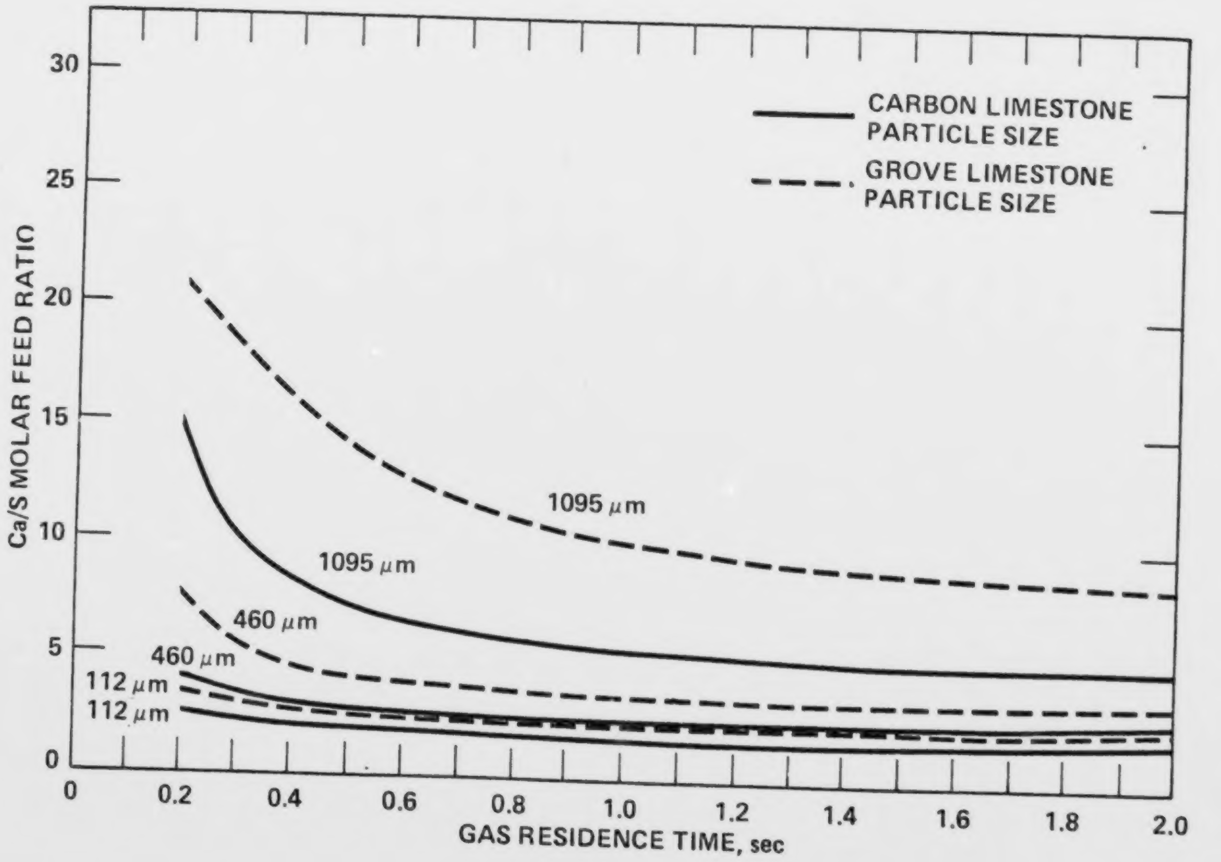


Figure 4.6-3. Ca/S molar feed required to maintain 90 percent sulfur removal in AFBC, as projected by the Westinghouse Model.[215]

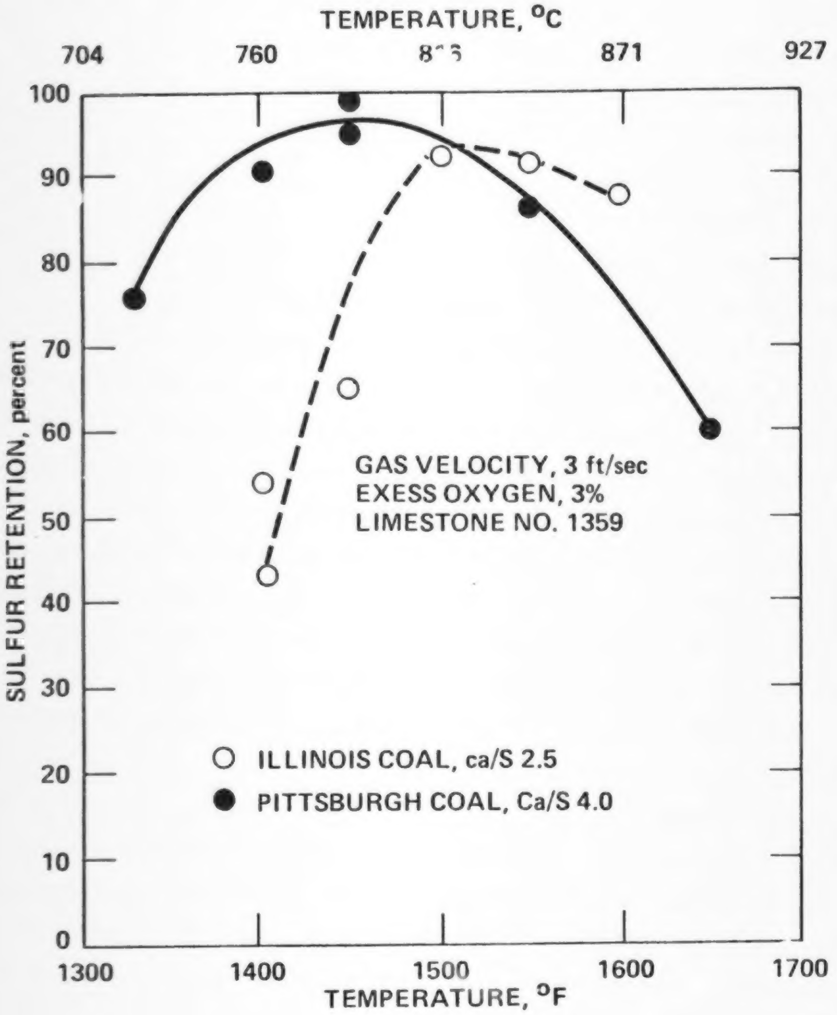


Figure 4.6-4. SO_2 reduction as a function of bed temperature.[218]

at temperatures greater than the optimum temperature may be caused by the release of SO_2 after capture due to local reducing conditions in the bed, or by slight changes in other variables.[219]

NO_x Control. Design and operating factors which influence the formation and control of NO_x in AFBC boilers include:

- Temperature
- Excess air
- Gas residence time
- Fuel nitrogen
- Coal particle size
- Factors affecting local reducing conditions

The kinetics and mechanisms of NO_x reduction in AFBC boilers are not well understood. Research to date indicates over 98 percent of NO_x emissions are NO and, furthermore, over 90 percent of the NO emitted is derived from fuel nitrogen. Surprisingly, however, NO_x emissions appear to be relatively independent of fuel nitrogen content. It is thought that NO is formed near the base of the bed and is then reduced to elemental nitrogen as the gases rise through the bed. Many of the factors above affect this reduction. In summary, AFBC boilers emit considerably less NO_x than conventional boilers because of the lower combustion temperatures. However, the further reduction of emissions by combustion modifications will probably need to await further investigation.[220]

Particulate Matter (PM) Control. For the most part, factors affecting the generation of PM emissions and the performance of control devices are similar to those affecting conventional boilers. FBC boilers can use fabric filters, ESP's and cyclones for PM control . Cyclones are commonly used for recycling elutriated bed material back to the boiler or to a separate carbon burnup cell.

4.6.1.3 Emission Test Data. Nearly all the available emission data for AFBC industrial boilers was obtained from tests run on small pilot plant or demonstration projects. Because these units are primarily research and development facilities, this test data may not be characteristic of full-scale industrial size units. In addition, the majority of the data has been obtained using sampling and analytical techniques other than EPA reference methods. Rigorous testing with established EPA reference test methods is usually done to determine whether a boiler is complying with specific emission standards. So far, the need for this type of testing has been limited.

The situation, insofar as the availability of standard test data obtained from full scale, continuously operating units, is changing rapidly. Several large scale commercial units are scheduled for start up within the next year and will likely require compliance tests.

SO_2 Emission Data Summary. Figure 4.6-5 is a summary of SO_2 data obtained at eight AFBC test facilities under a wide variety of test conditions. The bounded area is an indication of the range of performance expected from FBC systems at high gas-phase residence times and small sorbent particle size. Much of the experimental data falls within these boundaries. Deviations from the band are noted in the data from the B&W 3 ft x 3 ft unit and the PER-FMB unit. If the units and test conditions are considered closely these deviations from the band are expected. The B&W 3 ft x 3 ft unit has a shallow bed which allows less than optimum sorbent/gas contact. Gas phase residence times are approximately one- third of the recommended 0.67 sec. The PER-FBM data were also obtained using low gas-phase residence times in the range of 0.13 to 0.26 sec.[222]

A continuous emission monitoring program for SO_2 was conducted at the Georgetown University 45,400 kg (100,000 lb) steam/hr coal/limestone feed fluidized-bed boiler. Because this system was still in an extended shakedown phase, several key operating conditions (e.g., level of excess air, percent fly ash recycle) were not operating in the intended design range. On a daily average basis, desulfurization was greater than 75 percent on all 14 days of record, greater than 85 percent on 9 days, and greater than 90 percent on 5 days. Throughout the duration of the testing program boiler load varied between 50 to 60 percent. Coal feed properties ranged from 10 to 15 percent ash and 1.2 to 2.5 percent sulfur.[234] The complete SO_2 data set is presented in Appendix C.

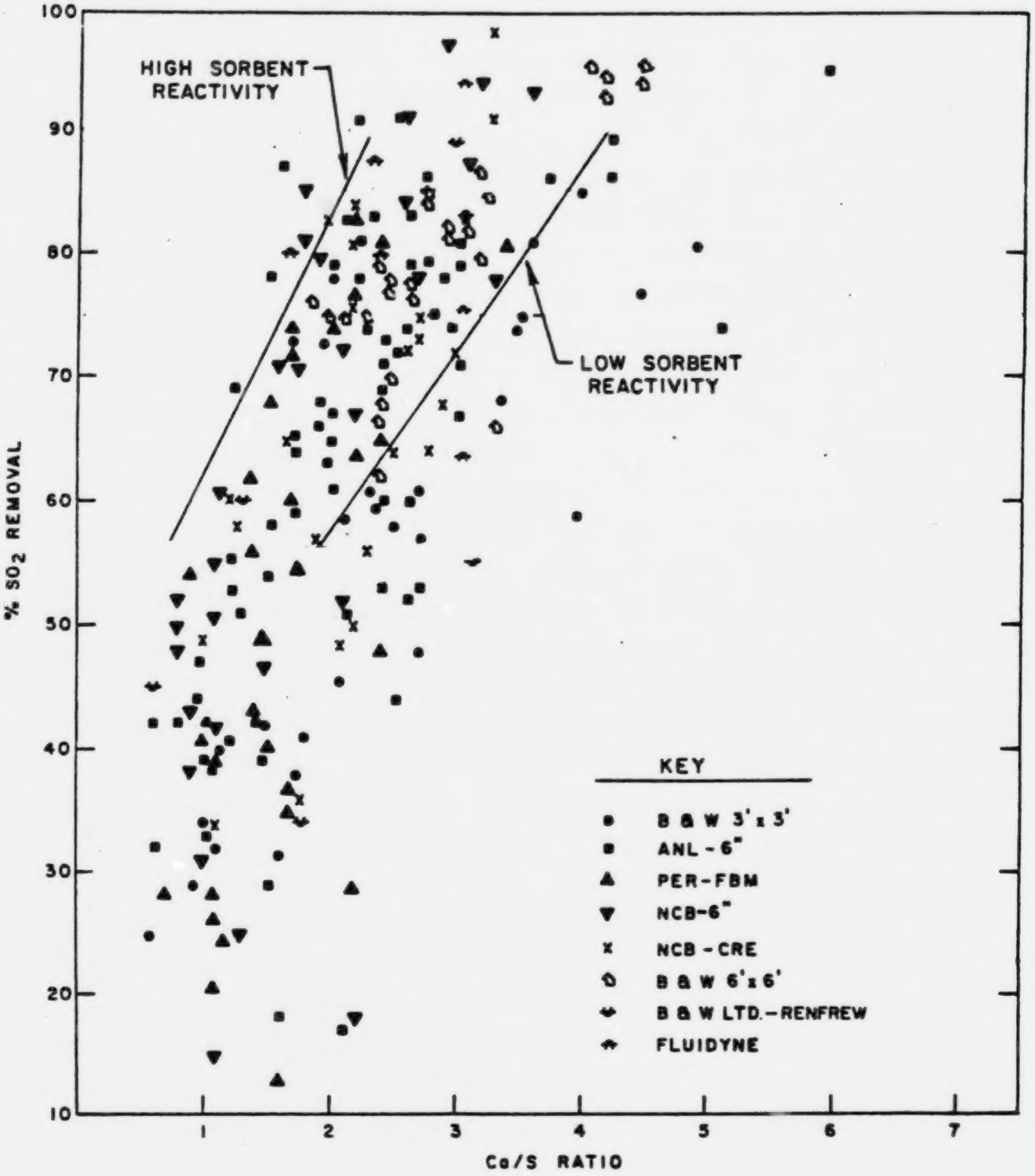


Figure 4.6-5 - Summary of data obtained at eight different AFBC test facilities. 219

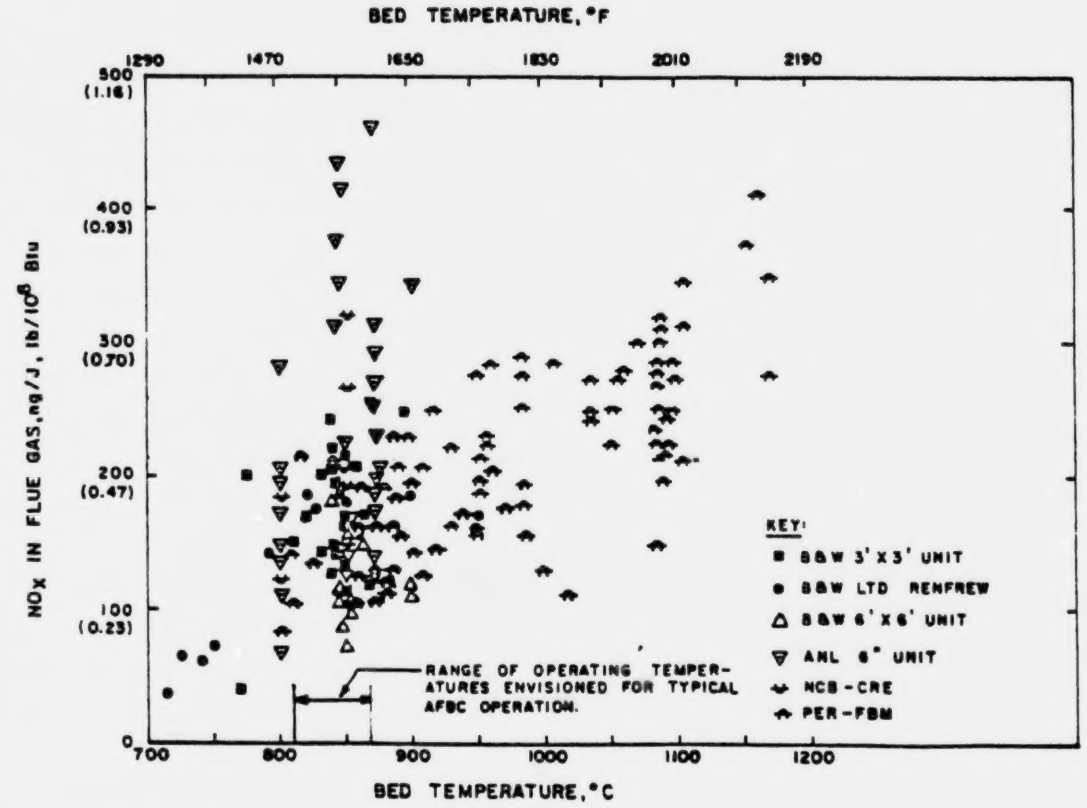
NO_x Emission Data Summary. The composite diagram of NO_x emission data measured over the range of normal FBC operating conditions is shown in Figure 4.6-6. In the temperature range of interest (800° to 900°C), most of the data points are below 215 ng/J (0.5 lb/10^6 Btu). However, about 10 percent of the test results in the temperature range of interest show NO_x emissions above 300 ng/J (0.7 lb/10^6 Btu). All of these higher values are from the Argonne 6 in. diameter bench-scale unit.[224]

These data are reported from experimentation with units where there was generally no intentional variation of design of operating conditions to reduce NO_x emissions. Increased gas residence times to enhance SO_2 control may contribute to additional reduction of NO_x emissions even further.[225]

A continuous emission monitoring program for NO_x was conducted at the Georgetown University 100,000 lb steam/hr coal/limestone feed fluidized-bed boiler. NO_x emissions ranged from 441 ng/J (1.0 lb/10^6 Btu) to 218 ng/J (0.5 lb/10^6 Btu) and averaged 281 ng/J (0.7 lb/10^6 Btu) for a 16 day period. Boiler load ranged from 48 to 61 percent capacity and percent oxygen values ranged from 8.8 to 12.3 percent on a dry basis. Fuel nitrogen was consistent at about 1.5 weight percent.[235] The complete test results are presented in Appendix C.

PM Emissions Data Summary. Available data concerning emissions from primary cyclones, which are considered part of the FBC boiler process, indicate that emissions at the cyclone outlet are in the range of 215 to 2150 ng/J (0.5 to 5.0 lb/10^6 Btu) with a mass mean particle size of 5 to 20 μm.[226] These emission characteristics are comparable to those for conventional mass feed spreader stokers. Thus, it is expected that controlled emissions from FBC boilers would be generally equivalent to those stokers equipped with the same controls (i.e., ESPs or fabric filters).

Table 4.6-1 summarizes the results from particulate emission tests conducted at the Georgetown University 45,400 kg (100,000 lb) steam/hr coal/limestone feed fluidized-bed boiler. The FBC unit is equipped with a mechanical collector and baghouse for particulate control. The percent ash in the fuel was high throughout the duration of the testing program and ranged between 10.6 and 15.0 percent on an as received basis. Average



*THESE POINTS ARE ESTIMATED FROM DATA REPORTED IN ppm, THUS THE ACCURACY OF THESE POINTS IS ASSUMED TO BE ± 30%

Figure 4.6-6 - Composite NO_x emissions diagram for FBC units operating within normal ranges.[220]

TABLE 4.6-1. RESULTS OF PARTICULATE EMISSION TESTING AT THE GEORGETOWN FBC UNIT.[234a]

Run number	August 23			September 13		
	P-1	P-2	P-3	P-4	P-5	P-6
Boiler load (lb/hr)	53,600	52,000	51,000	54,000	47,000	50,000
CO_2, %	8.0	8.0	8.0	8.9	8.0	8.0
O_2, %	11.5	11.5	11.5	10.1	10.6	10.6
Excess air, %	117.9	117.9	117.9	89.5	97.3	97.3
Avg. stack temp., °F	337.2	337.1	336.2	347.8	349.4	348.8
Stack gas volume, dscfm	18,890	19,245	18,296	17,607	18,121	18,177
Isokinetic ratio, %	96.74	95.87	98.58	98.56	98.40	98.36
Total particulate						
ng/J	47.04	37.79	24.58	32.31	20.92	19.62
lb/10^6 Btu	0.1094	0.0879	0.0572	0.0751	0.0487	0.0456
Average ng/J		36.5			24.3	
lb/10^6 Btu		0.0848			0.0565	

emissions ranged from 36.5 ng/J (0.0848 lb/10^6 Btu) to 24.3 ng/J (0.0565 lb/10^6 Btu) for the August and September tests, respectively. During the August set of runs there was noticeable puffing from the stack at regular intervals, indicating leakage in a compartment of the baghouse. After replacing several bags the extent of the puffing was reduced but not completely eliminated. An inspection of the baghouse prior to conducting the September runs revealed that extensive blinding of the teflon bags had occurred. After repairs were made, overall baghouse performance improved as evidenced by the results presented in Table 4.6-1. It should be noted that throughout the testing program mechanical collector plugging occurred which may have affected the inlet loading to the baghouse.[236]

4.6.2 Coal/Limestone Pellets

4.6.2.1 Process Description

4.6.2.1.1 System. Coal/limestone pellet (CLP) technology is an SO_2 removal technique currently being studied by the EPA. In this process, coal/limestone pellets are fired as ordinary fuel in stoker boilers. The SO_2 formed during combustion reacts with limestone present in the fuel pellets to form calcium sulfite and calcium sulfate salts. The majority of calcium salts remain in the ash bed and are discharged from the boiler along with the bottom ash. This system does produce an increase in boiler particulate emissions which may affect the design of fly ash control equipment.[227]

There are several processes available for the manufacture of CLP. These processes include the pellet mill process, briquette production process, auger extrusion process, and disk production process. In all cases the pellets are composed of coal, limestone and a cement or organic binder.

Pellet production studies have been conducted with the goal of producing a CLP suitable for industrial use.[228] Ideally, these pellets would have the mechanical strength, durability and weatherability characteristics comparable to those of raw coal. Table 4.6-2 compares the physical properties of coal and coal/limestone pellets (Ca:S ratio of 3.5) produced by two different processes using different binders. The mill production method creates a pellet with physical properties that exceed raw coal in all

TABLE 4.6-2. COMPARISON OF PHYSICAL PROPERTIES OF RAW COAL AND FUEL PELLET[229]

Production Method	Pellet Formulation(a)								Post Weathering	
	Coal		Limestone							
	Type	%	Type	%	Binder	Durability Index(b)	Compression Strength, lb	Weather Index(b)	Durability(b) Index	Strength, lb
Raw coal	Illinois #6	100	--	--	--	85 ± 2	74 ± 12	89 ± 1	75	58
Raw coal	E. Kentucky	100	--	--	--	85 ± 2	83 ± 22	94 ± 1	83	94
Raw coal	Lignite	100	--	--	--	77 ± 4	92 ± 22	80 ± 4	34	45
Raw coal	Rosebud	100	--	--	--	84 ± 2	50 ± 15	79 ± 2	20	68
CPM lab mill	Illinois #6	70	Piqua	30	2% Allbond + 1% Polyco 2136	87	112	100	85	>112
Bauner extrusion	Illinois #6	70	Piqua	30	1.5% Allbond 200 + 1% M-167 .01	94	84	100	62	60

(a) Water added as needed.

(b) Percent survival = 100 - percent fines.

respects while the extrusion process produces a pellet with properties comparable to raw coal.

4.6.2.1.2 Developmental status. The use of CLP as an SO_2 control technique for industrial boilers is still in the developmental stage. It must be shown to be economically viable, applicable to industrial boilers and effective at removing SO_2 before commercialization can begin.

As part of an EPA-funded program to evaluate this technology, studies aimed at resolving these questions are currently underway. These studies include:

- Battelle Columbus Labs: assess the technologies SO_2 removal capabilities for various boiler types, fuel types and quality. Development of a suitable pelletizing process.

- Versar, Inc.: address the impacts of this technology on boiler design. Evaluation of Battelle pelletizing process.

- Charles River Associates and Versar: address the cost to produce the pellets, marketing aspects and ability of potential pellet vendors to supply the projected demand.

At this time final results from the studies mentioned above are not available. However, some preliminary information has been supplied in the form of pellet production and emission data studies conducted by Battelle. These preliminary data indicate that Battelle-Columbus Laboratories has developed a pellet (Ca:S 3.5:1) suitable for industrial use with sulfur retention capability of about 50 percent. However, problems with the pelletizing process have impeded continued development.

4.6.2.1.3 Applicability to Industrial Boilers. Coal/limestone pellet SO_2 control technology is applicable to any type of coal-fired stoker boiler. Preliminary data suggest that bed temperature, steam production rate, fly ash loading, and bottom ash loading will be affected to some degree when firing coal/limestone in stoker boilers.[229]

Based on preliminary data from a "demonstration test" conducted at the Battelle Lab steam plant, it was found that CO levels from pellet firing were relatively high (usually greater than 100 ppm) compared to those from the firing of conventional stoker coals. These higher CO levels may be related to the nature of the burn and/or to the fact that the overfire air flow rate was decreased during the pellet firings. Because of the compactness of the pellet and the limited access of air into the pellet, the capture process first involves the formation of calcium sulfide via

$$2\,CaO + FeS_2 \rightarrow 2CaS + FeO + CO$$

which can account for the part of this increase in CO.

Particulate emissions at the outlet of the mechanical collector during the "demonstration test" from the firing of the 3.5:1 Battelle pellet were 258 ng/J (0.6 $lb/10^6$ Btu). The smoke opacity was only 20 percent which would appear low for a particulate loading of 258 ng/J (0.6 $lb/10^6$ Btu) if the fly ash were from coal firing alone. Fly ash from pellet firing is about 50 percent more dense and considerably more coarse than from firing coal alone.[228] For equivalent mass loadings, optical density varies inversely with particle size and density. Thus, the apparent discrepancy between smoke opacity and particulate loading is explained partially by the laws of optics. A change in particle size distribution over that of raw coal firing could affect the design of fly ash collection equipment. However, additional data are needed (particle size distributions) in order to quantify this effect.

Boiler thermal efficiency may be affected by the addition of limestone to the boiler feedstock. Limestone present in the bed will absorb thermal energy that would normally be used to produce steam. Numerical estimates for the potential efficiency reduction are not currently available. In addition the calcination of limestone is an endothermic reaction which will further reduce the thermal efficiency.

For an existing coal-fired boiler using CLP technology, the steam production rate is expected to be reduced by 20 percent of the rated capacity.[229] This is due primarily to a decrease in the heating value (Btu/lb fuel) of the coal/limestone mix relative to that of raw coal. In order to produce the energy equivalent of 100 kg (220 lb) of coal, 163 kg (359 lb) of coal/limestone mix would have to be burned.[229] Therefore, it is unlikely that a boiler could achieve its rated steam production capacity unless modifications to the fuel feeder mechanism prove successful in providing increased mass feed rates to the boiler.

Flue gas volumetric flow rate is expected to increase by 8 percent over that of raw coal firing.[229] This increase can be attributed to the CO_2 produced when calcining of calcium carbonate (limestone) occurs by the reaction:

$$CaCO_3 \rightarrow CaO \text{ (sorbert) } + CO_2$$

This increased flow is expected to affect the design and cost of new boilers and could affect the performance of existing boilers and controls using CLP. Wider tube spacing will be required on new boilers in order to maintain the standard design velocity past the tubes. In existing boilers using coal/limestone pellets this increased velocity could affect the heat transfer rate while simultaneously increasing corrosion of the tubes. Increased I.D. fan horsepower will also be required in order to accommodate the higher flue gas volume for both new and existing installations.

Total ash loading on the boiler and controls can be expected to increase with CLP use. Initial estimates show that 3 to 4 times as much ash may be generated over that of raw coal firing.[228] The impact resulting from this could take the form of increased bottom ash capacity and/or an increased number of bottom ash removal cycles, both which would affect boiler capital and/or maintenance costs.

The factors mentioned in this section could affect the applicability of this technology to industrial boilers with respect to boiler design, operation, maintenance and cost.

4.6.2.2 Factors Affecting Performance. An important factor affecting the performance of coal/limestone pellets as an SO_2 control technique is the calcium/sulfur ratio. A preliminary test using pellets with a 7:1 ratio demonstrated between 70-80 percent sulfur removal. Subsequent tests using pellets with a 3.5:1 ratio show removal efficiencies of from 45-67 percent. The calcium/sulfur ratio also affects the physical properties of the fuel (strength, durability and weatherability) and thus, the handling characteristics of the pellets. When conducting tests on the 7:1 ratio pellets, it was found that they lacked strength and broke under the stress from the fuel feed system. Although broken pellets may not affect SO_2 removal, particulate emissions may be increased.

A second factor affecting SO_2 removal efficiency appears to be the combustion or bed temperature. In preliminary tests on a small spreader stoker using pellet ratios of 7:1 and 3.5:1, removal efficiencies from 52-72 percent were reported (see emissions data section). Thermochemistry suggests that sulfur capture is reduced at higher bed temperatures. Additionally, an analytical model developed to serve as an interpretive tool suggests that maximum sulfur capture occurs for a minimum pellet surface area/volume ratio.[228] Thus, it is not surprising that the pillow-shaped briquet with a relatively high surface area/volume ratio has the lowest sulfur capture of any of the production techniques.

4.6.2.3 Emissions Data. A series of preliminary emissions tests have been conducted using coal/limestone pellets developed by Battelle- Columbus Labs. Initial model spreader tests used both the 3.5:1 and 7:1 Battelle pellets as the feedstock to a 20 brake horse power model spreader stoker boiler. Subsequent demonstration and checkout tests were conducted on an 11,340 kg/hr (25,000 lb steam/hr) spreader stoker at Battelle Laboratories using the 3.5:1 Battelle pellet only. In all of the tests a high sulfur coal was used (3-4 percent sulfur) to produce the pellets. Because these units are primarily research and development facilities, these test data may not be characteristic of full-scale commercial units.

Results from the model spreader stoker tests are summarized in Table 4.6-3. A preliminary test, using a raw coal feedstock was run to

TABLE 4.6-3. MODEL SPREADER STOKER EXPERIMENTS[228]

Fuel	Ca/S	Production Technique	Measured SO_2,(a) ppm	Predicted SO_2, ppm	Sulfur Retention, percent
Illinois No. 6	0	--	3700	3700	0
Cement-bound pellets	7	Pellet mill (cylinders)	1040	3700	72
Cement-bound pellets	3-1/2	Ditto	1220	3700	67
Methylcellulose-bound pellets	3-1/2	Ditto	1480	3700	60
Ditto	Ditto	Ditto	1260	3700	67
Ditto	Ditto	Briquettes	1780	3700	52
Ditto	Ditto	Auger extrusion (cylinders)	1370	3700	63
Ditto	Ditto	Disc (spheres)	Pellets did not have adequate strength		

TABLE 4.6-4. EMISSION DATA SUMMARY FOR FUEL PELLET DEMONSTRATION[228]

Load, pph	O_2, %	CO_2, %	CO, ppm	NO, ppm	SO_2, ppm	Smoke Opacity, %	CO at 3% O_2, ppm	NO at 3% O_2, ppm		Fuel N Converted, %	SO_2 at 3% O_2, ppm		Fuel S Emitted %	Particulates, lb/M Btu
								Computed	Measured		Computed	Measured		
20,000	8.4	10.5	300	310	1600	20	420	2250	440	20	4100	2250	55	0.6

TABLE 4.6-5. SULFUR BALANCE

Computed Fuel S In, lb/10^6 Btu	Emitted as SO_2 lb/10^6 Btu	Sulfur Retained In Bed Ash as SO_2, lb/10^6 Btu
7.4	4.1	3.3

document uncontrolled emissions. Sulfur retention values for the model spreader tests were calculated using this as the baseline emission level. The 7:1 Battelle pellet achieved 72 percent sulfur retention while the 3.5:1 pellets demonstrated retentions of from 52-67 percent. Variations in sulfur capture for the 3.5:1 pellet were attributed to variations in bed temperatures, with sulfur capture tending to be reduced at higher bed temperatures. Further testing of the 7:1 Battelle pellet was not conducted due to its lack of physical strength.

A demonstration test was conducted using twenty tons of CLP with a Ca:S ratio of 3.5. The pellets were fired in an 11,340 kg/hr (25,000 lb/hr) steam spreader-stoker boiler at the Battelle steamplant. Two types of pellets were used, a lower density (0.9 to 1.2 g/cc) pellet produced by Banner Industries using auger extrusion and a higher density pellet (1.4 g/cc) produced by Alley-Cassetty Coal Company using a pellet mill. Both types of the pellets were fired under a variety of boiler conditions. During the demonstration tests, the pellet feed rate was maintained at approximately 1.36 Mg/hr (1.5 tons/hr) at a boiler load of 80 percent. Tables 4.6-4 and 4.6-5 summarize the results of this test. As indicated in Table 4.6-4, the sulfur capture was 45 percent during the demonstration test. The greater sulfur retention of the earlier model spreader tests was attributed to the lower bed temperatures which were seldom higher than 1260°C (2300°F). The bed temperatures during the demonstration tests were seldom less than 1371°C (2500°F) and as high as 1455°C (2650°F). Additionally with a pulsating ash discharge stoker, the fuel bed is violently disturbed. Ash can therefore be recirculated back into the hot zone. Thus, if sulfur is retained in the ash at a lower bed temperature, it may be released when the ash is exposed to a higher temperature.

The Battelle steam plant boiler facility uses a mechanical collector to control particulate matter. Depending on the ash and sulfur content of the coal, earlier experiments had shown that particulate loadings varied between 86 and 258 ng/J (0.2 and 0.6 $lb/10^6$ Btu). Generally, for low S, low ash coals, particulate loadings were less than 129 ng/J (0.3 $lb/10^6$ Btu). The particulate loading during the demonstration test was 258 ng/J (0.6 lb/10^6 Btu).

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5.0 MODIFICATION AND RECONSTRUCTION

Standards of performance are applicable to facilities whose construction, modification, or reconstruction commenced after proposal of the standards. Such facilities are termed "affected facilities." Standards of performance are not applicable to "existing facilities" which are facilities whose construction, modification, or reconstruction commenced on or before proposal of the standards. However, an existing facility may become an affected facility and therefore subject to standards, if the facility undergoes modification or reconstruction.

Modification and reconstruction are defined under 40 CFR 60.14 and 60.15, respectively. The definition of "commenced" appears in 40 CFR 60.2. Modification and reconstruction provisions are summarized in Section 5.1 of this chapter. Section 5.2 discusses the applicability of the provisions to fossil fuel-fired industrial boilers.

5.1 SUMMARY OF MODIFICATION AND RECONSTRUCTION PROVISIONS

5.1.1 Modification

With certain exceptions, any physical or operational change to an existing facility that would result in an increase in the emission rate to the atmosphere of any pollutant to which a standard of performance applies would be considered a modification within the meaning of Section 111 of the Clean Air Act. The key to a modification determination is whether total emissions to the atmosphere (expressed in kg/hr) from the facility as a whole would increase as a result of the change. For example, if the affected facility is defined as a group of pieces of equipment, then the aggregate emissions from all the equipment must increase before the facility will be considered modified.

Exceptions which allow certain changes to an existing facility without it becoming an affected facility, irrespective of an increase in emissions, are listed below:

1. Routine maintenance, repair, and replacement.
2. An increase in production rate without a capital expenditure (as defined in 40 CFR 60.2).
3. An increase in the hours of operation.
4. Use of an alternate fuel or raw material if, prior to the standard, the existing facility was designed to accommodate that alternate fuel or raw material.
5. The addition or use of any system or device whose primary function is the reduction of air pollution, except when an emission control system is removed or is replaced by a system determined by EPA to be less environmentally beneficial.
6. Relocation or change in ownership of the existing facility.

Once an existing facility is determined to be modified, all of the emission sources of that facility are subject to the standards of performance for the pollutant whose emission rate increased and not just the emission source which displayed the increase in emissions. However, a modification to one existing facility at a plant will not cause other existing facilities at the same plant to become subject to standards.

An owner or operator of an existing facility who is planning a physical or operational change that may increase the emission rate of a pollutant to which a standard applies, shall notify the Administrator 60 days prior to the change, as specified in 40 CFR 60.7(a)(4).

5.1.2 Reconstruction

An existing facility may also become subject to new source performance standards if it is determined to be "reconstructed." As defined in 40 CFR 60.15, a reconstruction is the replacement of the components of an existing facility to the extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable new facility and (2) it is technically and economically feasible for the facility to meet the applicable standards. Because EPA considers reconstructed facilities to constitute new construction rather than modification, reconstruction determinations are made irrespective of changes in emission rate. Determinations are made on a case-by-case basis. If the facility is determined to be reconstructed, it must comply with all of the provisions of the standards of performance applicable to that facility.

If an owner or operator of an existing facility is planning to replace components and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable new facility, the owner or operator shall notify the Administrator 60 days before the construction of the replacements commences.

5.2 APPLICABILITY OF MODIFICATION AND RECONSTRUCTION PROVISIONS TO FOSSIL FUEL-FIRED INDUSTRIAL BOILERS

5.2.1 Modification

Actions which may increase emissions and therefore may be considered modifications include changes in the type of fuel fired and changes in the boiler components. These changes are discussed below.

5.2.1.1 Fuel Switching. The combustion of an alternate fuel will not be deemed a modification so long as an existing boiler was designed to accommodate the alternate fuel as discussed in 40 CFR 60.14(e)(4). Any other switch in fuel which increases the emissions of a regulated pollutant may constitute a modification, with the exception of fuel switches described in Section 111(a)(8) of the Clean Air Act and those specifically excluded by the standard.

5.2.1.2 Physical and Operational Changes. Physical changes could be made to many components of a fossil fuel-fired industrial boiler. This section summarizes some of the changes which may result in emissions increases.

Combustion Air System. The air flow in a boiler's draft system can be increased by changing fans and air nozzles in order to correct combustion problems and to reduce tubing corrosion. This change could result in greater excess air and higher air velocities which in turn could increase particulate matter and NO_x emissions. Other changes in air flow include altering the ratio of air added over (overfire air) and under (underfire air) the grates. Increasing the velocity of underfire air may also result in increased particulate matter carryover.

Flue Gas Handling System. Alterations can be made in the flue gas handling system by adding an economizer and/or air preheater, or by replacing the primary fan. The addition of an economizer would not increase the emission rate of any pollutant and thus would not be termed a modification. The addition of an air preheater, however, could increase furnace temperatures and NO_x formation. The likelihood of an owner or operator installing an air preheater is high.[1]

Fly Ash Reinjection. A system to reinject fly ash or unburned carbon particulate matter from stoker-fired boilers can be added to improve the overall fuel combustion efficiency and reduce overall operating costs. Fly ash reinjection increases the boiler particulate loading and therefore may increase emissions. Rapidly rising fuel costs tend to make this alternative more attractive and may cause some existing facilities to either add injection systems or increase injection rates in the future.[1]

5.2.2 Reconstruction

In a reconstruction determination, when components are replaced as part of a maintenance program the capital expenditures for each component are first adjusted by the annual asset guideline repair allowance percentage (Internal Revenue Service Publication 534) as specified in 40 CFR 60.2. Replacement of single boiler components would not likely require sufficient capital to subject an existing facility to the reconstruction provisions but, replacement of groups of components (e.g., retubing and rebricking) may result in sufficient expenditures to subject the facility to these provisions.

It does not appear likely that existing boilers that undergo normal repair and maintenance practices will become affected facilities by virtue of the reconstruction provisions. The National Board Inspection Code defines repairs as the following items:[2]

- Replacement of sections of boilers tube, provided the remaining part of the tube is not less than 75 percent of its original thickness.
- Seal welding of tubes.
- Building-up of certain corroded surfaces.
- Repairs of cracked ligaments of drums or headers within certain definite limits.

The types of maintenance that will usually require substantial amounts of time are boiler cleaning and repair or replacement of various parts. Primary maintenance areas for solid fuel-fired boilers are the fuel feed system and the fuel firing mechanism.

5.2.3 Summary

Modification determinations depend upon a physical or operational change that results in an increased emission rate. Reconstruction determinations, made by the Administrator on a case-by-case basis, depend on the level of capital expenditures and on the technological and economic feasibility of meeting the standard.

It appears that the reconstruction provisions could cause some existing boilers to be reclassified as affected facilities. In addition, there are boiler modifications that could result in an existing boiler becoming classified as an affected facility subject to new source performance standards. Likely examples are additions of a fly ash reinjection system or an air preheater or some types of fuel switching.

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6.0 MODEL BOILERS AND CONTROL ALTERNATIVES

The impacts of various control alternatives applied to fossil fuel-fired industrial boilers are assessed through an analysis of "model boilers". The model boiler evaluation provides a boiler-specific analysis of the environmental, energy, and cost impacts resulting from the application of different emission control techniques to various types and sizes of industrial boilers. This chapter defines the model boilers. Chapters 7 and 8 provide the environmental, energy, and cost impact analyses for the model boilers.

Figure 6-1 presents a simplified illustration of the three-step approach used in developing model boilers. The first step, discussed in Section 6.1, is to select a group of "standard boilers". These standard boilers are boilers without emission controls that represent the population of new industrial boilers expected to be built. The second step, discussed in Section 6.2, is to select appropriate control alternatives for each standard boiler. The alternatives are combinations of emission levels and/or emission reduction requirements for NO_x, SO_2, and PM. Each level and/or reduction requirement is based on the performance of control methods as presented in Chapter 4. The last step, discussed in Section 6.3, is to combine the standard boilers with emission control methods to form model boilers. Each model boiler represents a standard boiler controlled to the emission levels and/or reduction requirements specified in a control alternative. The environmental, energy, and cost impacts associated with each model boiler provide an estimate of the impacts of applying a specific control method to a specific boiler type. In general, the model boilers are selected to cover a range of boiler sizes, fossil fuel types, and control methods.

This model boiler selection process results in the generation of 61 model boilers representing the application of various NO_x, SO_2, and PM

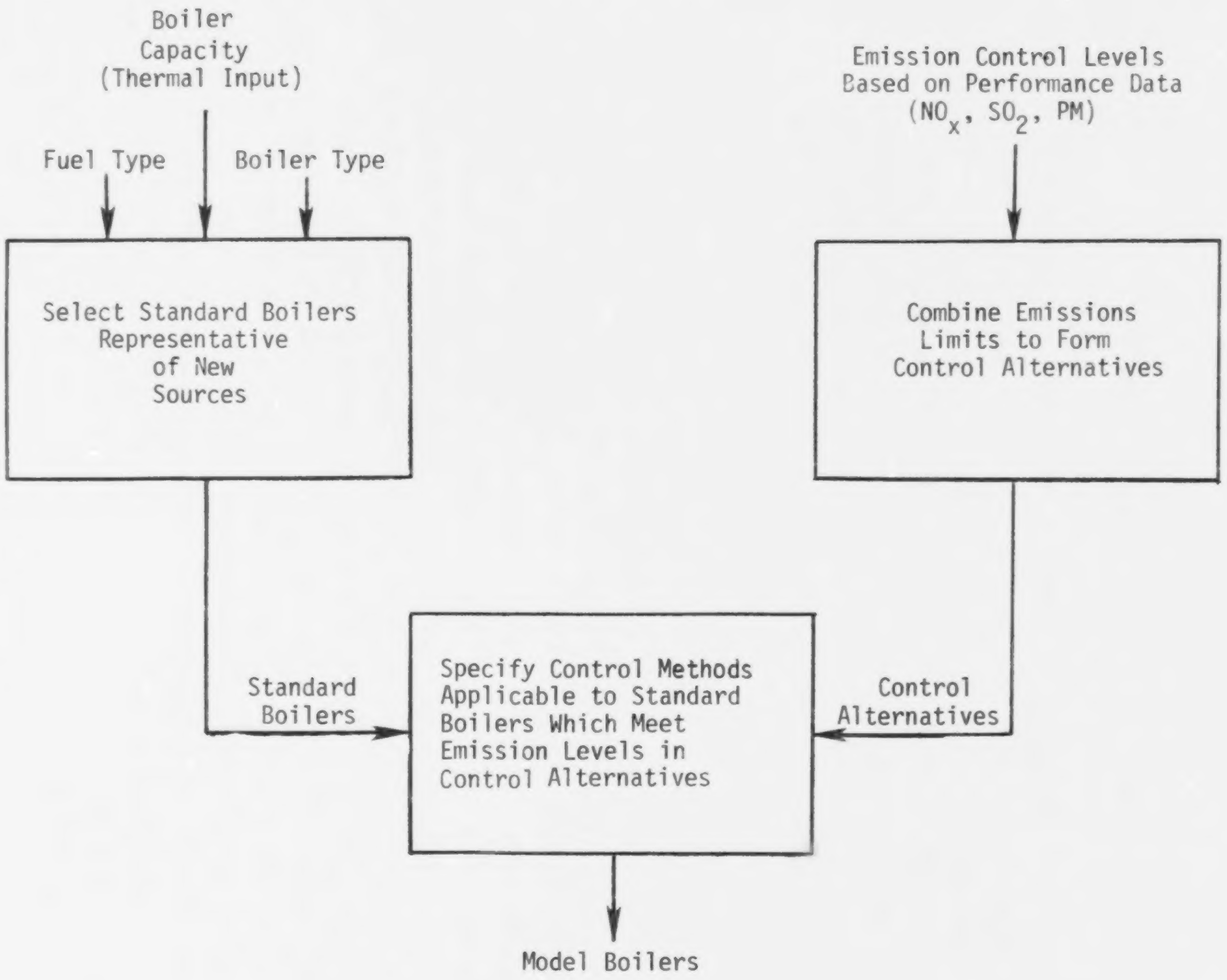
Boiler
Capacity
(Thermal Input)
Fuel Type
Boiler Type
Emission Control Levels
Based on Performance Data
(NO_x, SO_2, PM)
Select Standard Boilers Representative of New Sources
Combine Emissions Limits to Form Control Alternatives
Standard Boilers
Control Alternatives
Specify Control Methods Applicable to Standard Boilers Which Meet Emission Levels in Control Alternatives
Model Boilers

Figure 6-1. Logic leading to selection of model boilers.

control technologies presented in Chapter 4. In addition to these model boilers, five "emerging technology" model boilers are defined in Appendix E. These model boilers are used to estimate the environmental, energy, and cost impacts of various technologies that are still in the development stage, but have the potential to become commercially viable control technologies. The emerging control technologies are discussed in Chapter 4 and the model boiler impacts are presented in Appendix E.

6.1 SELECTION OF STANDARD BOILERS

Standard boilers are selected to represent the new industrial boiler population. Factors considered in their selection include boiler fuels, firing methods, heat transfer configurations, and boiler distribution by capacity. A summary of the standard boilers selected for evaluation is presented in Table 6-1.

6.1.1 Capacities and Fuel Type

The boiler capacities and fuels reflected in the standard boilers represent current and future designs based on the industrial boiler population data presented in Chapter 3. The principal industrial boiler fossil fuels are coal, residual oil, distillate oil, and natural gas. Standard boilers are selected to represent each of the basic fuel types. Since coal properties such as sulfur and ash content can vary considerably, separate standard boilers are selected for both low sulfur coal (LSC) and high sulfur coal (HSC) applications. Representative boiler design capacities within each fuel type are then selected to cover the range of expected capacities for the new industrial boiler population.

Many new industrial boilers are expected to fire mixtures of fossil and nonfossil fuels. Mixed-fuel boilers are evaluated in a companion study for which a separate Background Information Document (BID) has been prepared.[1]

As discussed in Chapter 3, capacities of industrial boilers range from less than 0.4 MW (1.5×10^6 Btu/hr) to greater than 146.5 MW (500×10^6 Btu/hr) thermal input. The majority of boilers at the lower end of the capacity range are used for space heating whereas the boilers at the

TABLE 6-1. STANDARD BOILERS SELECTED FOR EVALUATION

Boiler Code	Fuel	Heat Input Thermal MW,	(10^6Btu/hr)	Boiler Configuration
NG-30	Natural Gas	8.8	(30)	Package, Firetube
NG-150		44.0	(150)	Package, Watertube
DIS-30	Distillate Oil	8.8	(30)	Package, Firetube
DIS-150		44.0	(150)	Package, Watertube
RES-30	Residual Oil	8.8	(30)	Package, Firetube
RES-150		44.0	(150)	Package, Watertube
RES-400		117.2	(400)	Field-Erected, Watertube
HSC-30	High-Sulfur Coal	8.8	(30)	Package, Watertube, Underfeed Stoker
HSC-75		22.0	(75)	Field-Erected, Watertube, Chaingrate Stoker
HSC-150		44.0	(150)	Field-Erected, Watertube, Spreader Stoker
HSC-400		117.2	(400)	Field-Erected, Watertube, Pulverized Feed
LSC-30	Low-Sulfur Coal	8.8	(30)	Package, Watertube, Underfeed Stoker
LSC-75		22.0	(75)	Field-Erected, Watertube, Chaingrate Stoker
LSC-150		44.0	(150)	Field-Erected, Watertube, Spreader Stoker
LSC-400		117.2	(400)	Field-Erected, Watertube, Pulverized Feed

upper end of the capacity range are generally used for process steam and, in some cases, electricity generation.

The industrial boiler population capacity range is segmented into four size categories, with appropriate standard boilers chosen to represent each capacity interval, as noted in Table 6-2. These four categories span a range of capacities from 8.8 to 117.2 MW (30 to 400 x 10^6 Btu/hr). Two capacities are selected to represent the range of natural gas-fired and distillate oil-fired boilers while three are selected for residual oil-fired boilers. The natural gas- and distillate oil-fired units are represented in the small sizes by a 8.8 MW (30 x 10^6 Btu/hr) boiler and in the large capacities by a 44 MW (150 x 10^6 Btu/hr) boiler. The residual oil-fired boiler population tends to be larger and is represented by a 8.8 MW (30 x 10^6 Btu/hr), a 44 MW (150 x 10^6 Btu/hr), and a 117.2 MW (400 x 10^6 Btu/hr) boiler. All the natural gas- and oil-fired boilers are package units with the exception of the largest residual oil-fired standard boiler which is a field-erected unit. The construction of large oil-fired boilers is expected to be quite limited due to the high cost of oil in comparison to coal. However, a large residual oil-fired standard boiler is included to represent possible cases in which combinations of low residual oil and/or high coal prices make oil-firing economical.

In contrast to oil- and natural gas-fired boilers, coal-fired units vary greatly in firing methods and emission characteristics across their capacity range. As a result, coal-fired boilers have been selected for evaluation as standard boilers at all capacity intervals with thermal input capacities of 8.8 MW (30 x 10^6 Btu/hr), 22 MW (75 x 10^6 Btu/hr), 44 MW (150 x 10^6 Btu/hr), and 117.2 MW (400 x 10^6 Btu/hr).

6.1.2 Standard Boiler Configurations

In addition to fuel type and capacity, industrial boilers also vary according to heat transfer configuration. The three basic heat transfer configurations presented and discussed in Chapter 3 are cast iron, firetube, and watertube. No cast iron boilers have been selected for evaluation due primarily to their very small size and corresponding low emissions. Cast iron boilers are typically found in the small capacity sizes (less than

TABLE 6-2. REPRESENTATIVE STANDARD BOILER CAPACITIES

Capacity range (thermal input)	Coal (HSC & LSC)	Residual oil	Distillate oil	Natural gas
7.3-14.7 MW (25-50 x 10^6 Btu/hr)	8.8 MW (30 x 10^6 Btu/hr)	8.8 MW (30 x 10^6 Btu/hr)	8.8 MW (30 x 10^6 Btu/hr)	8.8 MW (30 x 10^6 Btu/hr)
14.7-29.3 MW (50-100 x 10^6 Btu/hr)	22 MW (75 x 10^6 Btu/hr)			
29.3-73.3 MW (100-250 x 10^6 Btu/hr)	44 MW (150 x 10^6 Btu/hr)	44 MW (150 x 10^6 Btu/hr)	44 MW (150 x 10^6 Btu/hr)	44 MW (150 x 10^6 Btu/hr)
>73.3 MW (>250 x 10^6 Btu/hr)	117.2 MW (400 x 10^6 Btu/hr)	117.2 MW (400 x 10^6 Btu/hr)		

0.1 MW or 0.4 x 10^6 Btu/hr) and are primarily fired with natural gas and/or distillate fuel oil. Firetube boilers are generally larger than cast iron boilers and tend to fire more coal, however, most units larger than 8.8 MW (30 x 10^6 Btu/hr) are watertube boilers. Therefore, all the standard boilers are of the watertube type except for the smallest 8.8 MW (30 x 10^6 Btu/hr) gas- and oil-fired model boilers.

The firing mechanisms or burners for natural gas- and oil-fired boilers are essentially the same across their capacity ranges. (Exceptions have been noted in Chapter 3). As a result, no differentiation in the firing methods has been made for the fuel oil- and natural gas-fired standard boilers. Coal-fired boilers, however, may be equipped with one of several different firing mechanisms or methods. The uncontrolled emissions, costs, and energy requirements of these boilers are influenced by these differences.

Underfeed stokers typically occupy the lower end of the capacity range, and pulverized coal the upper end, with other stoker types occupying the intermediate range between underfeed and pulverized coal-fired units. Exceptions do occur, with some boiler types appearing across the capacity range. Because more than 60 percent of the total number of coal-fired industrial boilers in the 2.9 to 14.7 MW (10 to 50 x 10^6 Btu/hr) thermal input capacity range are underfeed stokers, an 8.8 MW (30 x 10^6 Btu/hr) underfeed stoker has been selected as representative of that range. The chaingrate stoker and spreader stoker are the common firing mechanisms for medium-sized industrial boilers, with the chaingrate stoker being the more common firing method for boilers represented by the 22 MW (75 x 10^6 Btu/hr) unit. More than 60 percent of the stoker-fired boilers in the 29.3 to 73.3 MW (100 to 250 x 10^6 Btu/hr) thermal input capacity range are spreader stokers; thus a spreader stoker firing mechanism has been selected for the 44 MW (150 x 10^6 Btu/hr) capacity coal boiler. Pulverized coal-fired units account for only 15 percent of the coal-fired boilers in the thermal input capacity range from 29.3 to 73.3 MW (100-250 x 10^6 Btu/hr) however, the percentage increases toward the upper end of the capacity range.[2] Pulverized coal-fired boilers comprise 58 percent of the coal-fired boilers in the 73.3 to 147 MW (250 to 500 x 10^6 Btu/hr) thermal input capacity range. Since the lower end of the 29.3 to 73.3 MW (100 to 250 x 10^6 Btu/hr) range is represented by the spreader stoker, pulverized coal firing has been selected for the 117.2 MW (400 x 10^6 Btu/hr) capacity coal boilers.

Seventy-five percent of all boilers in the 29.3 to 73.3 MW (100 to 250 x 10^6 Btu/hr) thermal input capacity range are field-erected units.[3] The percentage is even higher for coal-fired units. As a result, coal-fired boilers selected as standard boilers are all field-erected units, with the exception of the 8.8 MW (30 x 10^6 Btu/hr) underfeed stoker unit which is a package boiler.

6.1.3 Standard Boiler Specifications

The specifications for the standard boilers are used in the "model boiler" environmental, energy, and cost analyses. The primary specifications relevant to these analyses are:

- Fuel type and quality
- Steam capacity and load factor
- Flue gas characteristics

Each of these factors are discussed in the following sections. The specifications for all of the standard boilers are presented in Tables 6-3 through 6-7. Additional specifications required for cost analysis, including control device specifications, are presented in Chapter 8.

6.1.3.1 Fuels. The fuel specifications have been chosen to represent currently available alternatives for industrial boiler fuels and are presented in Table 6-8. The fuel characteristics, including heating value and chemical analysis, are used to determine the combustion-related characteristics of the standard boilers. Natural gas, distillate oil, and residual oil are each represented by one type of fuel. The fuel characteristics presented for these fuels are based on data for "average" fuels.[4] The values selected for distillate oil represent No. 2 fuel oil and have been selected from average values. One exception is the value for sulfur content which is chosen from the upper part of the range for distillate oil. The analysis for the residual oil has been selected from the range of values given for No. 6 fuel oil; again, all values are taken from the middle of the

TABLE 6-3. SPECIFICATIONS FOR NATURAL GAS-FIRED STANDARD BOILERS (NG-30, NG-150)

Thermal input, MW (10^6 Btu/hr)	8.8 (30)	44.0 (150)
Fuel rate, m^3/hr (ft^3/hr)	850 (30,000)	4250 (150,000)
Analysis		
% sulfur	Trace	Trace
% ash	Trace	Trace
Heating value, kJ/kg (Btu/lb)	50,707 (21,800)	50,707 (21,800)
Excess air, %	15	15
Flue gas flow rate, m^3/s (acfm)	5.28 (11,200)	26.44 (56,000)
Flue gas temperature, K (°F)	450 (350)	450 (350)
Load factor, %	45	55
Flue gas constituents,[c] kg/hr (lb/hr)		
Fly ash	Trace	Trace
SO_2	Trace	Trace
NO_x	1.63 (3.6)[d]	16.34 (36.00)[d]
CO	0.26 (0.52)	1.15 (2.56)
HC as CH_4	0.04 (0.09)	0.20 (0.46)
Thermal output, MW (10^6 Btu/hr)		
Steam	7.04 (24.0)	38.28 (130.5)
Losses[a]	1.76 (6.0)	5.72 (19.5)
Efficiency (%)	80.0	87.0
Steam quality		
Pressure, kPa (psi)	1170 (170)	5170 (750)
Temperature, K (°F)	464 (375)	672 (750)
Steam production kg/hr (lb/hr)[b]	10,580 (23,300)	47,800 (105,300)

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[a] Losses include flue gas sensible heat, flue gas water vapor latent heat, and boiler radiative and convective losses.

[b] Assuming a saturated condensate return at 10 psig.

[c] Uncontrolled emissions.

[d] Uncontrolled NOx emissions on a ng/J (lb/10^6Btu) basis are higher for NG-150 boiler due to use of air preheater on larger unit.

TABLE 6-4. SPECIFICATIONS FOR DISTILLATE OIL-FIRED STANDARD BOILERS (DIS-30, DIS-150)

Thermal input, MW (10^6 Btu/hr)	8.8 (30)	44.0 (150)
Fuel rate, m^3/hr (gal/hr)	0.818 (216)	4.09 (1080.0)
Analysis		
% sulfur	0.5	0.5
% ash	Trace	Trace
Heating value, kJ/kg (Btu/lb)	45,346 (19,500)	45,346 (19,500)
Excess air, %	15	15
Flue gas flow rate, m^3/s (acfm)	5.38 (11,400)	26.9 (57,000)
Flue gas temperature, K (°F)	450 (350)	450 (350)
Load factor, %	45	55
Flue gas constituents,[c] kg/hr (lb/hr)		
Fly ash	Trace	Trace
SO	6.75 (15.3)	34.71 (76.50)
NO^x	1.63 (3.60)[d]	16.34 (36.00)[d]
CO^x	0.49 (1.08)	2.44 (5.40)
HC as CH_4	0.10 (0.22)	0.49 (1.08)
Thermal output, MW (10^6 Btu/hr)		
Steam	7.04 (24.0)	38.28 (130.5)
Losses[a]	1.76 (6.0)	5.72 (19.5)
Efficiency (%)	80.0	87.0
Steam quality		
Pressure, kPa (psi)	1170 (170)	5170 (750)
Temperature, K (°F)	464 (375)	672 (750)
Steam production, kg/hr (lb/hr)[b]	10,580 (23,300)	47,814 (105,300)

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[a] Losses include flue gas sensible heat, flue gas water vapor latent heat, and boiler radiative and convective losses.

[b] Assuming a saturated condensate return at 10 psig.

[c] Uncontrolled emissions.

[d] Uncontrolled NOx emissions on a ng/J (lb/10^6Btu) basis are higher for DIS-150 boiler due to use of air preheater on larger unit.

TABLE 6-5. SPECIFICATIONS FOR RESIDUAL OIL-FIRED STANDARD BOILERS (RES-30, RES-150, RES-400)

Thermal input, MW (10^6 Btu/hr)	8.8 (30)	44.0 (150)	117.2 (400)
Fuel rate, m^3/hr (gal/hr)	0.76 (200)	3.79 (1001)	10.11 (2670)
Analysis			
% sulfur	3.0	3.0	3.0
% ash	0.1	0.1	0.1
Heating value, kJ/kg (Btu/lb)	43,043 (18,500)	43,043 (18,500)	43,043 (18,500)
Excess air, %	15	15	15
Flue gas flow rate, m^3/s (acfm)	5.17 (10,950)	25.80 (54,740)	68.89 (145,960)
Flue gas temperature, K (°F)	478 (400)	478 (400)	478 (400)
Load factor, %	55	55	55
Flue gas constituents,[c] kg/hr (lb/hr)			
Fly ash	3.13 (6.90)	15.65 (34.5)	41.73 (91.92)
SO_x	43.77 (96.30)	218.47 (481.5)	582.59 (1283.24)
NO_x	5.44 (12.0)	27.22 (60.0)	72.59 (159.89)
CO	0.45 (1.0)	2.27 (5.0)	6.05 (13.33)
HC as CH_4	0.09 (0.20)	0.45 (1.0)	1.20 (2.64)
Thermal output, MW (10^6 Btu/hr)			
Steam	7.48 (25.5)	37.40 (127.5)	99.73 (340.38)
Losses[a]	1.32 (4.50)	6.60 (22.5)	17.60 (60.07)
Efficiency (%)	85.0	85.0	85.0
Steam quality			
Pressure, kPa (psi)	1030 (150)	5170 (750)	5170 (750)
Temperature, K (°F)	458 (365)	672 (750)	672 (750)
Steam production, kg/hr (lb/hr)[b]	11,368 (25,044)	48,815 (107,760)	130,440 (287,360)

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[a] Losses include flue gas sensible heat, flue gas water vapor latent heat, and boiler radiative and convective losses.

[b] Assuming a saturated condensate return at 10 psig.

[c] Uncontrolled emissions.

TABLE 6-6. SPECIFICATIONS FOR HIGH-SULFUR COAL-FIRED STANDARD BOILERS (HSC-30, HSC-75, HSC-150, HSC-400)

Thermal input, MW (10^6 Btu/hr)	8.8 (30)	22.0 (75)	44.0 (150)	117.2 (400)
Fuel rate, kg/s (ton/hr)	0.32 (1.27)	0.80 (3.18)	1.60 (6.36)	4.27 (16.95)
Analysis				
% sulfur	3.5	3.5	3.5	3.5
% ash	10.6	10.6	10.6	10.6
Heating value, kJ/kg (Btu/lb)	27,477 (11,800)	27,447 (11,800)	27,447 (11,800)	27,447 (11,800)
Excess air, %	50	50	50	30
Flue gas flow rate, m^3/s (acfm)	5.76 (12,224)	14.42 (30,560)	28.85 (61,120)	66.84 (141,600)
Flue gas temperature, K (°F)	478 (400)	478 (400)	478 (400)	478 (400)
Load factor, %	60	60	60	60
Flue gas constituents,[c] kg/hr (lb/hr)				
Fly ash	30.22 (66.60)	75.54 (166.50)	396.10 (873.00)	1304.3 (2876.00)
SO_2	77.59 (171.00)	193.96 (427.50)	387.93 (855.00)	1034.0 (2280.00)
NO_x	4.75 (10.50)	11.23 (24.75)	42.88 (94.50)	137.9 (304.00)
CO	1.15 (2.54)	2.88 (6.36)	5.76 (12.72)	7.7 (16.95)
HC as CH_4	0.58 (1.28)	1.44 (3.18)	2.88 (6.36)	2.3 (5.09)
Output, MW (10^6 Btu/hr)				
Steam	6.86 (23.4)	17.57 (59.9)	35.58 (121.3)	97.39 (332.4)
Losses[a]	1.94 (6.6)	4.93 (15.1)	8.42 (28.7)	19.81 (67.6)
Efficiency (%)	78.0	79.9	80.9	83.1
Steam quality				
Pressure, kPa (psi)	1030 (150)	1030 (150)	3100 (450)	5170 (750)
Temperature, K (°F)	458 (365)	458 (365)	589 (600)	672 (750)
Steam production, kg/hr (lb/hr)[b]	10,315 (22,723)	26,440 (58,247)	48,502 (106,850)	127,010 (280,000)

[a] Losses include flue gas sensible heat, flue gas water vapor latent heat, and boiler radiative and convective losses.

[b] Assuming a saturated condensate return at 10 psig.

[c] Uncontrolled emissions.

TABLE 6-7. SPECIFICATIONS FOR LOW-SULFUR COAL-FIRED STANDARD BOILERS (LSC-30, LSC-75, LSC-150, LSC-400)

Thermal input, MW (10^6 Btu/hr)	8.8 (30)	22.0 (75)	44.0 (150)	117.2 (400)
Fuel rate, m^3/hr (gal/hr)	0.39 (1.56)	0.99 (3.91)	1.98 (7.82)	5.25 (20.83)
Analysis				
% sulfur	0.6	0.6	0.6	0.6
% ash	5.4	5.4	5.4	5.4
Heating value, kJ/kg (Btu/lb)	22,330 (9,600)	22,330 (9,600)	22,330 (9,600)	22,330 (9,600)
Excess air, %	50	50	50	30
Flue gas flow rate, m^3/s (acfm)	5.92 (12,535)	14.79 (31,339)	29.58 (62,677)	68.71 (145,572)
Flue gas temperature, K (°F)	450 (350)	450 (350)	450 (350)	450 (350)
Load factor, %	60	60	60	60
Flue gas constituents,[c] kg/hr (lb/hr)				
Fly ash	19.08 (42.00)	47.64 (105.00)	248.36 (547.50)	816.3 (1800.00)
SO_2	16.13 (35.60)	40.49 (89.25)	80.99 (178.50)	215.9 (476.00)
NO_x	4.75 (10.50)	11.23 (24.75)	42.88 (94.50)	137.9 (304.00)
CO	1.41 (3.12)	3.54 (7.82)	7.08 (15.62)	9.4 (20.83)
HC as CH_4	0.71 (1.56)	1.77 (3.91)	3.54 (7.81)	2.8 (6.24)
Output, MW (10^6 Btu/hr)				
Steam	6.89 (23.5)	17.72 (60.4)	35.85 (122.2)	97.89 (334.1)
Losses[a]	1.91 (6.5)	4.28 (14.6)	8.15 (27.8)	19.31 (65.9)
Efficiency (%)	78.3	80.5	81.5	83.5
Steam quality				
Pressure, kPa (psi)	1030 (150)	1030 (150)	3100 (450)	5170 (750)
Temperature, K (°F)	458 (365)	458 (365)	589 (600)	672 (750)
Steam production, kg/hr (lb/hr)[b]	10,331 (22,760)	26,672 (58,760)	49,044 (108,044)	126,740 (279,200)

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[a] Losses include flue gas sensible heat, flue gas water vapor latent heat, and boiler radiative and convective losses.

[b] Assuming a saturated condensate return at 10 psig.

[c] Uncontrolled emissions.

TABLE 6-8. ULTIMATE ANALYSES OF FUELS SELECTED FOR THE MODEL BOILER ANALYSIS[5]

Fuel	Composition, % by weight[a]							Heating value[a]
	Moisture	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	kJ/kg (Btu/lb)
Natural Gas	0.02	69.26	22.67	8.05[b]	Trace	Trace	0	50,707 (21,800)
Distillate Oil	0.05	87.17	12.28	Trace	Trace	0.5	Trace	45,346 (19,500)
Residual Oil	0.08	86.62	10.20	0.3[c]	Trace	3.00	0.10	43,043 (18,500)
Eastern high-sulfur high-ash coal	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,447 (11,800)
Western low-sulfur low-ash coal	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

[a] All analyses are based on engineering judgements by PEDCo about information provided by Babcock & Wilcox, reference 5.

[b] Unbound nitrogen, not fuel N_2 that can be converted to "Fuel" NO_x emissions. See Chaper 3.

[c] Fuel nitrogen contents of residual oils can vary widely and can have a significant effect on NO_x emissions (See Chapter 3). 0.3% has been chosen for the model boiler analysis, but a separate analysis of the effect of fuel N_2 on achievable NO_x emissions is discussed in Chapter 4.

ranges except the sulfur value, which is from the upper part of the range. The sulfur contents are taken from the upper end of the range in order to provide a worst case analysis and because boiler operators would select lower cost, higher sulfur fuels in the absence of constraints limiting SO_2 emissions.

Two types of coal are used to represent the range of coals available in the United States. These two coals bound the primary factors which affect emission characteristics and control device performance; sulfur content, ash content, and heating value. The coal chemical analysis data in Table 6-8 are based on the following fuels:

- Eastern high-sulfur, high-ash, bituminous coal (HSC)
- Western low-sulfur, low-ash, subbituminous coal (LSC)

Although there are several other types of coals suitable for industrial boiler use, the two fuels selected for this analysis adequately bound the range of impacts. Practical limits on the number of model boiler cases that could be analyzed is also a factor in the selection of HSC and LSC as the coal fuels for the model boiler analysis.

6.1.3.2 Steam Capacities and Load Factors. The capacities of the standard boilers selected in Section 6.1.1 are based on the maximum heat input to the boiler. The heat input determines the fuel firing rate using the heating value of the fuel. Capacities of industrial boilers, however, are often based on steam output. To quantify the steam output, the boiler thermal efficiency and the steam quality are specified. The boiler thermal efficiency, which is a measure of the boiler heat input transferred to the steam cycle, is a function of the fuel properties, firing method, flue gas characteristics, and boiler heat losses. The quality of the steam produced is specified in terms of temperature and pressure. The steam quality varies with the intended steam use. The steam temperatures and pressures specified for the standard boilers are those commonly found in industrial applications for the selected capacities.

The capacities of the standard boilers represent maximum firing rates. Boilers, however, seldom operate at maximum capacity year-round. To analyze impacts on an annual operating basis, an appropriate estimate of actual boiler usage must be provided. The load factor (or capacity utilization factor) is the actual annual fuel consumption as a percentage of the potential annual fuel consumption at maximum firing rate. Lower load factors generally represent "non-process" boilers or boilers used mainly for seasonal space heating and cooling, while the higher factors represent process boilers whose output is tied directly to plant production. For each standard boiler, representative average values from this range are selected based on previous boiler studies and on data for typical load factors.[6] Load factors selected for the standard boilers are presented in Tables 6-3 through 6-7 for each boiler type.[7]

6.1.3.3 Flue Gas Characteristics. Temperature, composition, and volumetric flow rate are the main flue gas characteristics upon which the design of emission control technologies are based. These characteristics are affected primarily by fuel composition and boiler excess air. Fuel analyses were presented earlier in Table 6-8. Table 6-9 presents ranges (percent by weight) of excess air common to different boiler types assuming no NO_x control by reduced excess air. A representative excess air value for each standard boiler is specified for each boiler type.

The pollutant concentrations in the flue gas exiting the boiler are calculated based on the excess air rate, the chemical composition of the fuel, the fuel firing rate, and the emission factors developed in Chapter 3. Tables 6-3 through 6-7 report emission rates on kg/hr (lb/hr) basis for each standard boiler. In Chapter 7, emission factors for the uncontrolled standard boilers, and for the model boilers controlled to various emission limits are presented on a ng/J (lb/10^6 Btu) basis.

The flue gas flowrates and NO_x emission rates are based on the excess air conditions specified in Table 6-9. The uncontrolled NO_x emission rates (on a ng/J or lb/10^6 Btu basis) for the NG-30 and DIS-30 boilers are much lower compared to the larger boilers since the firetube units used in this size range do not use air preheaters. Use of air preheaters tends to increase flame temperatures and NO_x emission rates as detailed in Chapter 4.

TABLE 6-9. TYPICAL EXCESS AIR REQUIREMENTS FOR INDUSTRIAL BOILERS[7]

Fuel	Type of burners	Typical Range for Excess air, (% by weight)	Specified excess air, for standard boiler (% by weight)
Coal (pulverized)	Partially water-cooled for dry ash removal	15-40	30
Coal (stoker)	Spreader stoker	30-60	50
	Chaingrate and traveling-grate stokers	15-50	50
	Underfeed stoker	20-50	50
Fuel oil	Multifuel and flat-flame	10-20	15
Natural gas	Multifuel	7-15	15

6.2 SELECTION OF CONTROL ALTERNATIVES

Control alternatives are defined as sets of emission limits and/or percent reduction requirements for NO_x, SO_2, and PM applied to standard (uncontrolled) boilers. The limits and/or reduction requirements are based on the performance of various emission control methods as presented in Chapter 4. The emission levels selected for the control alternatives include a baseline level and several levels involving increasingly stringent emission reductions from this baseline level. By comparing the impact at the baseline level to the impact at other emission levels, it is possible to estimate the incremental impacts associated with application of a given control system to a given boiler type.

6.2.1 Baseline Alternative

The baseline alternative represents the highest level of emissions expected under the current mix of existing regulations (SIPs and Subpart D). The control method selected to meet the baseline alternative generally represents the least degree of control applicable to a particular pollutant and standard boiler. In most cases, the baseline control method also represents the least expensive control method which might be used.

Table 6-10 details the emission levels selected for the baseline control alternative (other control alternatives are discussed in the next section). The following discussion reviews now the baseline levels were selected.

For boilers larger than or equal to 73 MW (250×10^6 Btu/hr) in capacity, the existing NSPS defines the highest levels of NO_x, SO_2, and PM expected. Table 3-19 presented earlier, outlines the emission limits specified in the existing NSPS (Subpart D) for large fossil fuel-fired boilers. Since all new boilers larger than 73 MW (250×10^6 Btu/hr) must comply with these standards, the emission levels in the existing NSPS have been adopted for the large boiler baseline alternative.

For boilers smaller than 73 MW (250×10^6 Btu/hr), the selection of a baseline alternative is complicated by a variation in SIPs among states. This variation can be seen in Chapter 3 where SIP regulations are presented.

TABLE 6-10. CONTROL ALTERNATIVES SELECTED FOR EVALUATION

	Emission Levels, ng/J (lb/10^6Btu)		
Alternatives	NO_x[a]	SO_2[a,b]	PM
Coal-fired, <73.3 MW (250 x 10^6 Btu/hr)			
Baseline	151-271 (0.33-0.63)	1076 (2.5)	172-258 (0.40-0.60)[d]
Alt. 1	215 (0.5)	860 (2.0)	86 (0.2)
Alt. 2	215 (0.5)	860 (2.0)	22 (0.05)
Alt. 3	215 (0.5)	50% Removal	43 (0.1)
Alt. 4	215 (0.5)	90% Removal	43 (0.1)
Alt. 5	215 (0.5)	90% Removal	22 (0.05)
Coal-fired, ≥73.3 MW (250 x 10^6 Btu/hr)			
Baseline	301 (0.7)	516 (1.2)	43 (0.1)
Alt. 1	258 (0.6)	50% Removal	43 (0.1)
Alt. 2	258 (0.6)	90% Removal	43 (0.1)
Alt. 3	258 (0.6)	90% Removal	22 (0.05)
Residual-fired, <73.3 MW (250 x 10^6 Btu/hr)			
Baseline	172 (0.40)	688 (1.6)	99 (0.23)
Alt. 1	129 (0.3)	344 (0.8)	43 (0.1)
Alt. 2	129 (0.3)	129 (0.3)	43 (0.1)
Alt. 3	129 (0.3)	90% Removal	43 (0.1)
Alt. 4	129 (0.3)	90% Removal	22 (0.05)
Residual-fired, ≥73.3 MW (250 x 10^6 Btu/hr)			
Baseline	129 (0.3)	344 (0.8)	43 (0.1)
Alt. 1	129 (0.3)	90% Removal	43 (0.1)
Alt. 2	129 (0.3)	90% Removal	22 (0.05)
Distillate oil-fired			
Baseline	52-104 (0.12-0.24)[c]	219 (0.51)	6 (0.015)
Alt. 1	43-86 (0.1-0.2)[c]	129 (0.3)	6 (0.015)
Natural gas-fired			
Baseline	52-104 (0.12-0.24)[c]	0.43(0.001)	4.3 (0.01)
Alt. 1	43-86 (0.1-0.2)[c]	0.43(0.001)	4.3 (0.01)

[a] NO_x and SO_2 emission limits and percent removal requirements shown are on a long-term average basis and do not represent requirements for a shorter interval such as 24-hrs.

[b] Percent removal limits indicate percent SO_2 emissions are reduced from uncontrolled.

[c] NO_x emission levels depend on use of air preheat. Larger boilers use air preheat and consequently have higher NO_x emissions.

[d] Lower level is for 8.8 MW and 22 MW boilers; higher level is for 44 MW boiler.

Under the average SIP, SO_2 emissions are limited to 688 ng/J (1.6 lb/10^6 Btu) for oil-fired boilers and 1075 ng/J (2.5 lb/10^6 Btu) for coal-fired boilers. These levels are selected to represent the baseline alternative for SO_2 for coal and residual oil-fired boilers smaller than 73 MW. Distillate oil- and natural gas-fired boilers have uncontrolled emission rates below these levels. Therefore, the uncontrolled emission level is selected to represent the baseline alternative for these boilers.

NO_x emissions from new industrial boilers smaller than 73 MW are generally not subject to emission limits under current SIPs. Therefore, the baseline alternative selected for NO_x for these boilers is the uncontrolled case for coal-, oil-, and gas-fired model boilers.

SIP particulate matter emission levels for coal-fired boilers are generally more variable than the NO_x and SO_2 emission levels. Variations in emission levels between states, boiler types, and boiler sizes make an average difficult to apply to this set of model boilers. However, in many states, the particulate matter emission limits for coal-fired boilers are met with the application of single mechanical collectors. Therefore, the single mechanical collector is selected to represent the control method applied under the baseline alternative. The emission level for mechanical collectors presented in Table 6-10 are based on the performance data presented and discussed in Chapter 4.

Particulate emissions from new oil- and gas-fired boilers are not subject to emission limitations under current SIPs. Therefore, the baseline alternative selected is the uncontrolled case. The emission levels presented in Table 6-10 are based on the uncontrolled emission rates for oil- and gas-fired boilers.

Because the emissions at baseline vary with respect to boiler size and fuel type, the 15 standard boilers are grouped into six classes of boilers using these parameters. These six classes are:

(1) < 73.3 MW (250 x 10^6 Btu/hr) coal-fired,

(2) > 73.3 MW (250 x 10^6 Btu/hr) coal-fired,

(3) < 73.3 MW (250 x 10^6 Btu/hr) residual oil-fired,

(4) > 73.3 MW (250 x 10^6 Btu/hr) residual oil-fired,

(5) distillate oil-fired, and

(6) natural gas-fired.

Separate control alternatives are developed for each class.

6.2.2 Other Alternatives

For each of the six classes of standard boilers, up to five alternatives involving further emission reductions beyond baseline are specified. These alternatives are shown in Table 6-10. The six categories of boilers in Table 6-10 correspond to the six classes of model boilers defined above. In general, the number of alternatives is reduced for the larger boilers since the available degree of control beyond baseline is reduced. Similarly, the number of alternatives for the distillate and natural gas-fired boilers are limited due to low uncontrolled emissions.

The emission levels and alternatives presented in Table 6-10 do not represent every possible type and form of an emission standard. There is a practical limit to the number of cases which can be examined on an individual boiler basis. The selected levels were chosen to permit environmental, energy, and cost impacts to be evaluated over a range of control alternatives and associated emission reductions.

6.3 SUMMARY OF CONTROL SYSTEMS AND MODEL BOILERS

A controlled standard boiler is termed a model boiler and is used to evaluate environmental, energy, and cost impacts of NO_x, SO_2, and PM control. Results of these evaluations are presented in Chapters 7 and 8.

Control methods selected to meet each emission limit or percent reduction requirement are based on the performance of the control method as presented in Chapter 4. In many cases, more than one emission control method or combination of control methods can achieve a specified control level. As general guidelines, model boiler control methods were selected based on the technology's ability to meet a specified emission limit, the development status and commercial availability. In the case of sidestream separator controls, the available emission data is very limited. The emission level assumed for purposes of this analysis may not be indicative of long term emission levels on individual boilers.

Control methods selected for model boiler evaluations include single mechanical collectors, sidestream separators, wet scrubbers (also used for SO_2 removal), electrostatic precipitators, HDS cleaned oils, and fabric filters for particulate control; low excess air, staged combustion air, and reduced air preheat for NO_x control; and HDS cleaned oils, low sulfur coal, double alkali scrubbing, dry scrubbing, and sodium throwaway scrubbing for SO_2 control. Since the cost and environmental impacts of the double alkali and lime/limestone SO_2 control systems have been shown to be very similar,[8] either of the processes could be used to evaluate impacts for wet SO_2 controls producing a sludge. The dual alkali process was selected to represent wet sludge-producing processes over the lime/limestone process since there are more industrial boiler dual alkali systems than lime/limestone systems.

The control systems selected to achieve the emission levels in each control alternative are shown in Tables 6-11 and 6-12 for coal-fired and oil/gas-fired boilers respectively. Abbreviations used in these tables are defined in Table 6-13. The emission limits in each regulatory alternative are repeated from Table 6-10. For each standard boiler/control system combination, a model boiler is defined. A total of 61 model boilers are defined in this manner.

In subsequent chapters, model boilers are often referred to by a code consisting of abbreviations for fuel type, boiler size, and control system. As an example, the following code,

HSC - 150 - SCA, FGD, ESP

refers to a high-sulfur coal-fired, 44 MW (150 x 10^6 Btu/hr) model boiler with staged combustion air, double alkali flue gas desulfurization scrubbing, and electrostatic precipitator controls. Similar codes are used for all model boilers.

TABLE 6-11. COAL-FIRED MODEL BOILERS

Standard Boiler[f]	Control Alternative	Emission Levels or Removal Requirements ng/J (lb/10^6 Btu)			Control System[e]		
		NO_x	SO_2	PM	NO_x	SO_2	PM
HSC-30 HSC-75 HSC-150	B	151-271(0.33-0.63)[c]	1076 (2.5)	172-258 (0.40-0.60)[c]	Unc	CC	SM
	1	215(0.5)	860 (2.0)	86 (0.2)[g]	SCA[b]	CC	SSS[g]
	2	215(0.5)	860 (2.0)	22 (0.05)	SCA[b]	CC	ESP
	3	215(0.5)	50% Removal	43 (0.1)	a	a	a
	4	215(0.5)	90% Removal	43 (0.1)	SCA[b]	FGD	FGD/PM
	5	215(0.5)	90% Removal	22 (0.05)	SCA[b]	FGD	ESP
LSC-30 LSC-30 LSC-150	B	151-271(0.33-0.63)[c]	1076 (2.5)	172-258 (0.40-0.60)[c]	Unc	Unc	SM
	1	215 (0.5)	860 (2.0)	86 (0.2)[g]	SCA[b]	Unc	SSS[g]
	2	215 (0.5)	860 (2.0)	22 (0.05)	SCA[b]	Unc	FF
	3	215 (0.5)	50% Removal	43 (0.1)	SCA[b]	DS	DS/PM
	4	215 (0.5)	90% Removal	43 (0.1)	SCA[b]	FGD	FGD/PM
	5	215 (0.5)	90% Removal	22 (0.05)	SCA[b]	FGD	FF
HSC-400	B	301 (0.7)	516 (1.2)	43 (0.1)	LEA	FGD[d]	FGD/PM
	1	258 (0.6)	50% Removal	43 (0.1)	a	a	a
	2	258 (0.6)	90% Removal	43 (0.1)	SCA	FGD	FGD/PM
	3	258 (0.6)	90% Removal	22 (0.05)	SCA	FGD	ESP
LSC-400	B	301 (0.7)	516 (1.2)	43 (0.1)	LEA	Unc	FF
	1	258 (0.6)	50% Removal	43 (0.1)	SCA	DS	DS/PM
	2	258 (0.6)	90% Removal	43 (0.1)	SCA	FGD	FGD/PM
	3	258 (0.6)	90% Removal	22 (0.05)	SCA	FGD	FF

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[a] 50% SO_2 removal alternative not applicable for HSC standard boilers since this removal would not meet baseline emission level. Therefore, no model boiler is analyzed for this alternative.

[b] SCA required on 44 MW (150 x 10^6 Btu/hr) size only; smaller boilers meet NOx level without control.

[c] Baseline emissions depend on boiler size and type (see text and Chapter 7).

[d] 78.9% SO_2 removal efficiency required at baseline.

[e] Abbreviations defined in Table 6-13. Unc (uncontrolled) indicates no control system is required to meet emission levels.

[f] Alternatives shown define model boilers for each standard boiler. For example, six model boilers are defined for HSC-30, six are defined for HSC-75, etc.

[g] SSS emission level based on limited emission data (see Chapter 4).

TABLE 6-12. OIL- AND GAS-FIRED MODEL BOILERS

Standard Boiler[c]	Control Alternative	Emission Levels or Removal Requirements ng/J (lb/10^6Btu)			Control System[b]		
		NO_x	SO_2	PM	NO_x	SO_2	PM
RES-30 RES-150	B	172 (0.4)	688 (1.6)	99 (0.23)	Unc	HDS (1.6)	Unc
	1	129 (0.3)	344 (0.8)	43 (0.1)	LEA	HDS (0.8)	HDS/PM
	2	129 (0.3)	129 (0.3)	43 (0.1)	LEA	HDS (0.3)	HDS/PM
	3	129 (0.3)	90% Removal	43 (0.1)	LEA	FGD[a]	FGD/PM
	4	129 (0.3)	90% Removal	22 (0.05)	LEA	FGD[a]	ESP
RES-400	B	129 (0.3)	344 (0.8)	43 (0.1)	LEA	FGD[d]	FGD/PM
	1	129 (0.3)	90% Removal	43 (0.1)	LEA	FGD	FGD/PM
	2	129 (0.3)	90% Removal	22 (0.05)	LEA	FGD	ESP
DIS-30	B	52 (0.12)	219 (0.51)	6 (0.015)	Unc	Unc	Unc
	1	43 (0.1)	129 (0.3)	6 (0.015)	LEA	HDS (0.3)	Unc
DIS-150	B	104 (0.24)	219 (0.51)	6 (0.015)	Unc	Unc	Unc
	1	86 (0.20)	129 (0.3)	6 (0.015)	LEA/RAP	HDS (0.3)	Unc
NG-30	B	52 (0.12)	0.43 (0.001)	4.3 (0.01)	Unc	Unc	Unc
	1	43 (0.1)	0.43 (0.001)	4.3 (0.01)	LEA	Unc	Unc
NG-150	B	104 (0.24)	0.43 (0.001)	4.3 (0.01)	Unc	Unc	Unc
	1	86 (0.20)	0.43 (0.001)	4.3 (0.01)	LEA/RAP	Unc	Unc

[a] Double alkali scrubbing (FGD) used on 44 MW (150 x 10^6 Btu/hr), sodium throwaway (FGD/Na) used on 8.8 MW (30 x 10^6 Btu/hr).

[b] Abbreviations defined in Table 6-13. Unc (uncontrolled) indicates no control system is required to meet emission levels.

[c] Alternatives shown define model boilers for each standard boiler. For example, five model boilers are defined for RES-30, five for RES-150, etc.

[d] 75% removal efficiency required at baseline.

TABLE 6-13. ABBREVIATIONS FOR CONTROL SYSTEMS

NO_x Control Systems

SCA - Staged combustion air (overfire air) used in combination with LEA
LEA - Low excess air
RAP - Reduced air preheat

SO_2 Control Systems

CC - Compliance coal[a]
FGD - Double alkali scrubbing flue gas desulfurization (90% removal unless noted)
FGD/Na - Sodium throwaway flue gas desulfurization (90% removal)
DS - Dry scrubbing (50% removal)
HDS(x) - Hydrodesulfurized oil (x percent sulfur)

PM Control Systems

SM - Single mechanical collector (multitube cyclone)
SSS - Sidestream separator
ESP - Electrostatic precipitator
FF - Fabric filter
FGD/PM- Particulate removal via FGD scrubber
DS/PM - Particulate removal via DS fabric filter
HDS/PM- Particulate removal via low ash HDS cleaned oil

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[a] Compliance coal is defined as a coal with a sulfur content allowing an emission limit to be met without control. The sulfur content is less than HSC but greater than LSC (actual sulfur content depends on emission limit, see Chapter 8.)

6.4 REFERENCES

1. U.S. Environmental Protection Agency. Background Information Document for Nonfossil Fuel Fired Boilers. Research Triangle Park, N.C. Publication No. EPA-450/3-82-007. March, 1982.

2. Devitt, T. (PEDCo Environmental, Inc.) Population and Characteristics of Industrial/Commercial Boilers in the U.S. (Prepared for U.S. Environmental Protection Agency.) Research Triangle Park, N.C. Publication No. EPA-600/7-79-178a. August 1979. p. 17.

3. Reference 2, p. 91.

4. Useful Tables for Engineers and Steam Users, Thirteenth Edition. New York, Babcock and Wilcox, 1978. p. 39.

5. Steam, Its Generation and Use, 38th Edition. New York, Babcock and Wilcox, 1975. pp. 5-1 to 5-22.

6. Reference 2, pp. 33-37, p. 110.

7. Reference 2, pp. 93-102.

8. Dickerman, J.C. and J.L. Johnson. (Radian Corporation). Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization. (Prepared for U.S. Environmental Protection Agency.) Research Triangle Park, N.C. Publication No. EPA-600/7-79-178i. November 1979. p. 1-3.

7.0 ENVIRONMENTAL AND ENERGY IMPACTS

An analysis of the environmental and energy impacts that result from applying various emission control technologies to individual fossil fuel-fired industrial boilers is presented in this chapter. Environmental and energy impacts of the emerging control technologies are presented in Appendix E. National and regional environmental and energy impacts resulting from application of various control technologies to the projected new industrial boiler population were analyzed using the Industrial Fuel Choice Analysis Model (IFCAM) and the results are presented in Chapter 10.

The environmental and energy impact analysis is based on an evaluation of the model boilers presented in Chapter 6. The objective of this chapter is to determine the incremental increase or decrease in air pollution, water pollution, solid waste generation, and energy usage for various alternative control levels compared to the baseline level. The baseline control level corresponds to no change in existing regulations and represents the controls required under the current mix of industrial boiler SIP and NSPS regulations (40 CFR Subpart D).

Tables 7-1 and 7-2 specify the NO_x, SO_2, and PM emission factors for the model boilers using no controls, baseline controls and various control alternatives outlined in Chapter 6. Emission factors for the control alternatives are developed in Chapter 6. The technologies used to meet these control alternatives are identified in Chapter 6 (Tables 6-11 and 6-12) and described in Chapter 4.

7.1 AIR POLLUTION IMPACTS

This section presents an analysis of the air pollution impacts associated with each model boiler. The air pollution impact analysis is divided into two main subsections as outlined below:

TABLE 7-1. SUMMARY OF EMISSION FACTORS FOR COAL-FIRED MODEL BOILERS

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Emission Factors (lb/10^6 Btu)[a] Uncontrolled	Baseline	Alt 1[b]	Alt 2	Alt 3[b]	Alt 4	Alt 5
HSC-30	30	NO_x	0.35	0.35	0.35	0.35	NA	0.35	0.35
		SO_2	5.70	2.50	2.00	2.00	NA	0.57	0.57
		PM	2.22	0.40	0.20	0.05	NA	0.10	0.05
HSC-75	75	NO_x	0.33	0.33	0.33	0.33	NA	0.33	0.33
		SO_2	5.70	2.50	2.00	2.00	NA	0.57	0.57
		PM	2.22	0.40	0.20	0.05	NA	0.10	0.05
HSC-150	150	NO_x	0.63	0.63	0.50	0.50	NA	0.50	0.50
		SO_2	5.70	2.50	2.00	2.00	NA	0.57	0.57
		PM	5.82	0.60	0.20	0.05	NA	0.10	0.05
HSC-400	400	NO_x	0.76	0.70	NA	0.60	0.60	NA	NA
		SO_2	5.70	1.20	NA	0.57	0.57	NA	NA
		PM	7.19	0.10	NA	0.10	0.05	NA	NA
LSC-30	30	NO_x	0.35	0.35	0.35	0.35	0.35	0.35	0.35
		SO_2	1.19	1.19	1.19	1.19	0.60	0.12	0.12
		PM	1.40	0.40	0.20	0.05	0.10	0.10	0.05
LSC-75	75	NO_x	0.33	0.33	0.33	0.33	0.33	0.33	0.33
		SO_2	1.19	1.19	1.19	1.19	0.60	0.12	0.12
		PM	1.40	0.40	0.20	0.05	0.10	0.10	0.05
LSC-150	150	NO_x	0.63	0.63	0.50	0.50	0.50	0.50	0.50
		SO_2	1.19	1.19	1.19	1.19	0.60	0.12	0.12
		PM	3.65	0.60	0.20	0.05	0.10	0.10	0.05
LSC-400	400	NO_x	0.76	0.70	0.60	0.60	0.60	NA	NA
		SO_2	1.19	1.19	0.60	0.12	0.12	NA	NA
		PM	4.50	0.10	0.10	0.10	0.05	NA	NA

[a] To convert to ng/J, multiply by 430.

[b] 50 percent SO_2 removal alternative not evaluated for HSC-fired model boilers.

TABLE 7-2. SUMMARY OF EMISSION FACTORS FOR OIL- AND GAS-FIRED MODEL BOILERS

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Emission Factors (lb/10^6 Btu)[a]					
			Uncontrolled	Baseline	Alt 1	Alt 2	Alt 3	Alt 4
RES-30	30	NO_x	0.40	0.40	0.30	0.30	0.30	0.30
		SO_2	3.21	1.60	0.80	0.30	0.32	0.32
		PM	0.23	0.23	0.10	0.10	0.10	0.05
RES-150	150	NO_x	0.40	0.40	0.30	0.30	0.30	0.30
		SO_2	3.21	1.60	0.80	0.30	0.32	0.32
		PM	0.23	0.23	0.10	0.10	0.10	0.05
RES-400	400	NO_x	0.40	0.30	0.30	0.30	NA	NA
		SO_2	3.21	0.80	0.32	0.32	NA	NA
		PM	0.23	0.10	0.10	0.05	NA	NA
DIS-30	30	NO_x	0.12	0.12	0.10	NA	NA	NA
		SO_2	0.51	0.51	0.30	NA	NA	NA
		PM	0.02	0.02	0.02	NA	NA	NA
DIS-150	150	NO_x	0.24	0.24	0.20	NA	NA	NA
		SO_2	0.51	0.51	0.30	NA	NA	NA
		PM	0.02	0.02	0.02	NA	NA	NA
NG-30	30	NO_x	0.12	0.12	0.10	NA	NA	NA
		SO_2	trace	trace	trace	NA	NA	NA
		PM	0.01	0.01	0.01	NA	NA	NA
NG-150	150	NO_x	0.24	0.24	0.20	NA	NA	NA
		SO_2	trace	trace	trace	NA	NA	NA
		PM	0.01	0.01	0.01	NA	NA	NA

[a] To convert to ng/J multiply by 430.

Primary Air Impacts (Section 7.1.1)

- model boiler annual emissions and emission reductions
- model boiler dispersion analysis.

Secondary Air Impacts (Section 7.1.2)

- annual emissions from facilities supplying power to operate pollution control devices.

The primary air impacts subsection presents the annual emissions for each control alternative and discusses the impacts of increasingly stringent control alternatives. Both source emissions and ambient air impacts are discussed. The secondary air impacts subsection evaluates emissions that result from facilities supplying electrical power to operate the pollution control devices as they are applied to individual boilers.

7.1.1 Primary Impacts

7.1.1.1 Model Boiler Emissions and Emission Reductions

Numerical emission factors for each model boiler control alternative are developed in Chapter 6 and presented in Tables 7-1 and 7-2. Uncontrolled model boiler emission factors are also included. Based on these emission factors, annual emissions of SO_2, PM and NO_x are tabulated in Tables 7-3 and 7-4 for all coal-, oil-, and gas-fired model boilers. Calculation of annual emissions is based on the percent of the boiler capacity used on an annual basis. These capacity utilization or load factors are as follows:

Boiler Capacity and Fuel	Load Factor
8.8 MW (30 x 10^6 Btu) Natural Gas & Distillate Oil	0.45
44 MW (150 x 10^6 Btu) Natural Gas & Distillate Oil	0.55
All residual-fired boilers	0.55
All coal-fired boilers	0.60

From the annual emissions presented in Tables 7-3 and 7-4, the annual emission reductions achieved under each control alternative are calculated. These emission reductions are quantified in two ways including: incremental annual emission reductions achieved over the baseline alternative and incremental percent reductions achieved over the baseline alternative.

TABLE 7-3. COAL-FIRED MODEL BOILER ANNUAL EMISSIONS

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Annual Emissions (Tons/yr)[a]						
			Uncontrolled	Baseline	Alt 1[b]	Alt 2	Alt 3[b]	Alt 4	Alt 5
HSC-30	30	NO_x	28	28	28	28	NA	28	28
		SO_2	449	197	158	158	NA	45	45
		PM	175	32	16	4	NA	8	4
HSC-75	75	NO_x	65	65	65	65	NA	65	65
		SO_2	1123	493	394	394	NA	112	112
		PM	438	79	39	10	NA	20	10
HSC-150	150	NO_x	248	248	197	197	NA	197	197
		SO_2	2247	986	788	788	NA	225	225
		PM	2294	237	79	20	NA	39	20
HSC-400	400	NO_x	799	736	NA	631	631	NA	NA
		SO_2	5992	1261	NA	599	599	NA	NA
		PM	7558	105	NA	105	53	NA	NA
LSC-30	30	NO_x	28	28	28	28	28	28	28
		SO_2	94	94	94	94	47	9	9
		PM	110	32	16	4	8	8	4
LSC-75	75	NO_x	65	65	65	65	65	65	65
		SO_2	235	235	235	235	118	24	24
		PM	276	79	39	10	20	20	10
LSC-150	150	NO_x	248	248	197	197	197	197	197
		SO_2	469	469	469	469	237	47	47
		PM	1439	237	79	20	39	39	20
LSC-400	400	NO_x	799	736	631	631	631	NA	NA
		SO_2	1251	1251	631	126	126	NA	NA
		PM	4730	105	105	105	53	NA	NA

[a] To convert to Mg/yr multiply by 0.908.

[b] 50 percent SO_2 removal alternative not calculated for HSC-fired model boilers.

TABLE 7-4. OIL- AND GAS-FIRED MODEL BOILER ANNUAL EMISSIONS

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Annual Emissions (Tons/yr)[a]					
			Uncontrolled	Baseline	Alt 1	Alt 2	Alt 3	Alt 4
RES-30	30	NO_x	29	29	22	22	22	22
		SO_2	232	116	58	22	23	23
		PM	17	17	7	7	7	4
RES-150	150	NO_x	145	145	108	108	108	108
		SO_2	1160	578	289	108	116	116
		PM	83	83	36	36	36	18
RES-400	400	NO_x	385	289	289	289	NA	NA
		SO_2	3093	771	308	308	NA	NA
		PM	222	96	96	48	NA	NA
DIS-30	30	NO_x	7	7	6	NA	NA	NA
		SO_2	30	30	18	NA	NA	NA
		PM	1	1	1	NA	NA	NA
DIS-150	150	NO_x	87	87	72	NA	NA	NA
		SO_2	184	184	108	NA	NA	NA
		PM	5	5	5	NA	NA	NA
NG-30	30	NO_x	7	7	6	NA	NA	NA
		SO_2	trace	trace	trace	NA	NA	NA
		PM	1	1	1	NA	NA	NA
NG-150	150	NO_x	87	87	72	NA	NA	NA
		SO_2	trace	trace	trace	NA	NA	NA
		PM	4	4	4	NA	NA	NA

[a] To convert to Mg/yr multiply by 0.908.

Emission reductions over baseline can be interpreted as the amount of the baseline emissions captured by applying a more stringent control alternative.

Annual emission and percent reductions over baseline are presented in Tables 7-5 and 7-7 for coal-fired model boilers, and Tables 7-6 and 7-8 for oil- and gas-fired model boilers. The following discussion focuses on these reductions and identifies trends across the range of impacts presented.

SO_2 Emission Reductions

Prior to a discussion of the trends shown, two general points are noted concerning application of the control alternatives. First, the baseline alternative for LSC-fired model boilers does not require application of controls. Uncontrolled SO_2 emissions from LSC-fired model boilers are below the levels required under the mix of existing regulations. Second, for HSC-fired model boilers, the alternatives requiring 50 percent SO_2 removal are not applied because the baseline alternatives for HSC-fired boilers are more stringent.

Several trends are evident in Tables 7-5 and 7-6 regarding SO_2 emission reductions from coal-fired model boilers. For model boilers smaller than 73 MW, HSC-fired boilers have the highest actual emission reductions. This occurs because the SO_2 emissions available for capture at baseline are about two times greater for HSC-fired boilers smaller than 73 MW (see Table 7-3). For Alternatives 3 and 4 where 90 percent SO_2 removal by flue gas desulfurization is applied, the emission reduction over baseline for the 44 MW (150 x 10^6 Btu/hr) HSC-fired model boiler is 691 Mg/yr (761 tons/yr). The emission reduction for the 44 MW LSC-fired model boiler is 383 Mg/yr (422 tons/yr). Under Alternatives 3 and 4 percent reduction over baseline values are 77 and 90 percent for the HSC- and LSC-fired model boilers, respectively.

For coal-fired model boilers larger than 73 MW (250 x 10^6 Btu/hr) this trend is reversed as a result of the relatively stringent baseline alternative applied to HSC-fired model boilers. Because 80 percent of the uncontrolled emissions from HSC-fired model boilers are captured at baseline, the alternatives requiring 90 percent removal result in a

TABLE 7-5. COAL-FIRED MODEL BOILER ANNUAL EMISSION REDUCTIONS OVER BASELINE

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Emission Reductions (Tons/yr)[a]				
			Alt 1[b]	Alt 2	Alt 3[b]	Alt 4	Alt 5
HSC-30	30	NO_x	0	0	NA	0	0
		SO_2	39	39	NA	152	152
		PM	16	28	NA	24	28
HSC-75	75	NO_x	0	0	NA	0	0
		SO_2	99	99	NA	380	380
		PM	39	69	NA	59	69
HSC-150	150	NO_x	51	51	NA	51	51
		SO_2	197	197	NA	761	761
		PM	158	217	NA	197	217
HSC-400	400	NO_x	NA	105	105	NA	NA
		SO_2	NA	662	662	NA	NA
		PM	NA	0	53	NA	NA
LSC-30	30	NO_x	0	0	0	0	0
		SO_2	0	0	47	84	84
		PM	16	28	24	24	28
LSC-75	75	NO_x	0	0	0	0	0
		SO_2	0	0	116	211	211
		PM	39	69	59	59	69
LSC-150	150	NO_x	51	51	51	51	51
		SO_2	0	0	233	422	422
		PM	158	217	197	197	217
LSC-400	400	NO_x	105	105	105	NA	NA
		SO_2	620	1125	1125	NA	NA
		PM	0	0	53	NA	NA

[a] To convert to Mg/yr multiply by 0.908.

[b] 50 percent SO_2 removal alternative not calculated for HSC-fired model boilers.

TABLE 7-6. OIL- AND GAS-FIRED MODEL BOILER ANNUAL EMISSION REDUCTIONS OVER BASELINE

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Emission Reductions (Tons/yr)[a]			
			Alt 1	Alt 2	Alt 3	Alt 4
RES-30	30	NO_x	7	7	7	7
		SO_2	58	94	93	93
		PM	9	9	9	13
RES-150	150	NO_x	36	36	36	36
		SO_2	289	470	463	463
		PM	47	47	47	65
RES-400	400	NO_x	0	0	NA	NA
		SO_2	463	463	NA	NA
		PM	0	48	NA	NA
DIS-30	30	NO_x	1	NA	NA	NA
		SO_2	12	NA	NA	NA
		PM	0	NA	NA	NA
DIS-150	150	NO_x	14	NA	NA	NA
		SO_2	76	NA	NA	NA
		PM	0	NA	NA	NA
NG-30	30	NO_x	1	NA	NA	NA
		SO_2	0	NA	NA	NA
		PM	0	NA	NA	NA
NG-150	150	NO_x	14	NA	NA	NA
		SO_2	0	NA	NA	NA
		PM	0	NA	NA	NA

[a] To convert to Mg/yr multiply by 0.908.

TABLE 7-7. COAL-FIRED MODEL BOILER PERCENTAGE EMISSION REDUCTIONS OVER BASELINE

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Reductions (Percent)				
			Alt 1[a]	Alt 2	Alt 3[a]	Alt 4	Alt 5
HSC-30	30	NO_x	0	0	NA	0	0
		SO_2	20	20	NA	77	77
		PM	50	88	NA	75	88
HSC-75	75	NO_x	0	0	NA	0	0
		SO_2	20	20	NA	77	77
		PM	50	88	NA	75	88
HSC-150	150	NO_x	21	21	NA	21	21
		SO_2	20	20	NA	77	77
		PM	67	92	NA	83	92
HSC-400	400	NO_x	NA	14	14	NA	NA
		SO_2	NA	53	53	NA	NA
		PM	NA	0	50	NA	NA
LSC-30	30	NO_x	0	0	0	0	0
		SO_2	0	0	50	90	90
		PM	50	88	75	75	88
LSC-75	75	NO_x	0	0	0	0	0
		SO_2	0	0	50	90	90
		PM	50	88	75	75	88
LSC-150	150	NO_x	21	21	21	21	21
		SO_2	0	0	50	90	90
		PM	67	92	83	83	92
LSC-400	400	NO_x	14	14	14	NA	NA
		SO_2	50	90	90	NA	NA
		PM	0	0	50	NA	NA

[a] 50 percent SO_2 removal alternative not evaluated for HSC-fired model boilers.

TABLE 7-8. OIL- AND GAS-FIRED MODEL BOILER PERCENTAGE EMISSION REDUCTIONS OVER BASELINE

Standard Boiler	Capacity (10^6 Btu/hr)	Emission Specie	Reductions (Percent)			
			Alt 1	Alt 2	Alt 3	Alt 4
RES-30	30	NO_x	25	25	25	25
		SO_2	50	81	80	80
		PM	57	57	57	78
RES-150	150	NO_x	25	25	25	25
		SO_2	50	81	80	80
		PM	57	57	57	78
RES-400	400	NO_x	0	0	NA	NA
		SO_2	60	60	NA	NA
		PM	0	50	NA	NA
DIS-30	30	NO_x	17	NA	NA	NA
		SO_2	41	NA	NA	NA
		PM	0	NA	NA	NA
DIS-150	150	NO_x	17	NA	NA	NA
		SO_2	41	NA	NA	NA
		PM	0	NA	NA	NA
NG-30	30	NO_x	17	NA	NA	NA
		SO_2	0	NA	NA	NA
		PM	0	NA	NA	NA
NG-150	150	NO_x	17	NA	NA	NA
		SO_2	0	NA	NA	NA
		PM	0	NA	NA	NA

relatively small incremental reduction over baseline in comparison to LSC-fired model boiler incremental reductions.

As a result of the low uncontrolled SO_2 emissions from natural gas- and distillate oil-fired model boilers, only one control alternative is evaluated which applied to distillate oil-fired model boilers. Alternative 1, where hydrodesulfurized fuel oil is applied, results in an 11 to 69 Mg/yr (12 to 76 tons/yr) emission reduction over baseline across the boiler size range.

Residual oil-fired boilers have higher uncontrolled SO_2 emissions due to the relatively higher sulfur content of residual fuel oil. From Table 7-4 it can be determined that baseline controls reduce SO_2 emissions by 50 percent for boilers smaller than 73 MW (250 x 10^6 Btu/hr), and by 75 percent for boilers larger than 73 MW (250 x 10^6 Btu/hr). As a result of this difference, the emission reductions over baseline for the most stringent control alternative (Alternative 2) are relatively high for boilers smaller than 73 MW. For Alternative 2, an emission reduction over baseline of 420 Mg/yr (463 tons/yr) is shown for the 117 MW (400 x 10^6 Btu/hr) model boiler while a 420 Mg/yr (463 tons/yr) reduction is also shown for the 44 MW model boiler. This represents percent reductions over baseline of 60 and 80 percent for the large and small model boilers, respectively. As with the small coal-fired boilers, this is a direct result of the high percentage of emissions available for capture at baseline for boilers smaller than 73 MW. These boilers are not subject to the more stringent NSPS for industrial boilers.

PM Emissions Reductions

As with SO_2 emissions, the natural gas- and distillate oil-fired boilers have low uncontrolled emissions and are not impacted by the control alternatives. There are no baseline controls required for residual oil-fired boilers smaller than 73 MW. Boilers larger than 73 MW are subject to the existing industrial boiler NSPS which requires emission reductions from the uncontrolled level. The most stringent control alternatives examined for residual oil-fired boilers result in incremental emission reductions of from 50 to 78 percent over baseline. As is the case with SO_2

emission reductions, the highest emission reductions occur for boilers not subject to the existing NSPS for industrial boilers (smaller than 73 MW) 250 x 10^6 Btu/hr)).

Baseline control alternatives for coal-fired model boilers vary as a function of boiler type and size range. As a result, percent reductions over baseline are variable as well, with the highest percent reductions occurring for model boilers not subject to the existing NSPS for industrial boilers (boilers smaller than 73 MW). Existing baseline controls for coal-fired boilers reduce uncontrolled PM emissions by 50 to 99 percent, with the highest percent removals occurring where electrostatic precipitators or fabric filters are applied (boilers larger than 73 MW). The most stringent control alternatives evaluated result in emission reductions over baseline of from 25 to 197 Mg/yr (28 to 217 tons/yr) for model boilers smaller than 73 MW (Alternative 5) and 48 Mg/yr (53 tons/yr) for model boilers larger than 73 MW (Alternative 3).

NO_x Emission Reductions

Unlike the SO_2 and PM impact analyses where several control alternatives and control methods were evaluated, the NO_x impact analysis examines only a limited number of emission levels achievable through combustion modifications.

No NO_x controls are required at the baseline control level for model boilers smaller than 73 MW (250 x 10^6 Btu/hr) whereas boilers larger than 73 MW are subject to the existing NSPS for industrial boilers. In addition, NO_x controls are not applied to underfeed and chaingate stokers since the uncontrolled NO_x emission rate for these boilers is less than the emission rate specified for any of the control alternatives examined.

In general, combustion modification reduces NO_x emissions from small (less than 73 MW) coal-fired model boilers by 14 to 21 percent using low excess air (LEA). For the 117 MW (400 x 10^6 Btu/hr) pulverized coal-fired model boilers, Table 7-7 shows a 14 percent reduction over baseline using staged combustion air (SCA). This represents an overall emission reduction of 21 percent over the uncontrolled emission rate. Emission reductions from the oil- and gas-fired model boilers investigated range from 17 to

25 percent over baseline by using low excess air (LEA) and low excess air/reduced air preheat (LEA/RAP). A 25 percent reduction from the uncontrolled level occurs for the 117 MW (400 x 10^6 Btu/hr) residual oil-fired boiler.

7.1.1.2 Model Boiler Dispersion Analysis. In order to assess the ambient air impacts of the model boiler air emissions, dispersion analyses were performed by the Source Receptor Analysis Division of the EPA. The ambient levels of NO_x, SO_2 and PM, resulting from the model boilers were estimated, using the single source CRSTR model. When the inputs (emission rates, meteorological data) are accurate, the computed concentrations have been found to have an uncertainty factor of about two. Based on this factor, the actual ambient concentrations could be greater by a maximum of two or less by a minimum of ½, than the concentrations calculated from the CRSTR model.

As a basis for the dispersion analysis, it was assumed that:

- The pollutants modeled displayed the dispersion behavior of a non-reactive gas.
- Sources were located on flat or gently rolling terrain in urban locations.
- Prevailing meteorological conditions were unfavorable to the dispersion of effluents.
- All model boiler stacks were modeled as continuous point sources of emissions.
- Receptors were located at plant grade (same elevation as the base of the stack).
- All emissions were emitted from one stack.

1964 meteorological data for St. Louis was used.

The dispersion modeling results are presented in Table 7-9, and were based on the emission rates presented in Tables 7-1 and 7-2. However,

TABLE 7-9. MODEL BOILER DISPERSION MODELING RESULTS

Model Boiler	Control Alternative	Maximum Downwind Ambient Air Concentration at Averaging Period $\mu g/m^3$ (10^{-6} gr/dscf)				
		NO_2[o]	SO_2[n]		Particulate[m]	
		Annual Mean	Annual Mean	Max.- 24 Hr.	Annual Mean	Max.- 24 Hr.
NG-30 UNC, UNC, UNC	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, UNC, UNC	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
DIS-30 UNC, UNC, UNC	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, HDS, UNC	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
RES-30 UNC, HDS, UNC	B	1.820[c] (.7859)	7.330[c] (3.165)	77.90[c] (33.64)	1.040[c] (.4491)	11.10[c] (4.793)
LEA, HDS, HDS	1	1.380[c] (.5959)	3.680[c] (1.589)	38.93[c] (16.81)	.4500[c] (.1943)	4.767[c] (2.058)
LEA, HDS, HDS	2	.1350[c] (.0583)	1.380[c] (.5959)	14.60[c] (6.304)	.4500[c] (.1943)	4.767[c] (2.058)
LEA, FGD(90)-Na, FGD	3	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90)-Na, ESP	4	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
HSC-30 UNC, CC, SM	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, SSS	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, ESP	2	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	.2855[d] (.1233)	.4670[d] (.2017)	5.820[c] (2.514)	.0807[d] (0349)	1.007[c] (.4350)
LEA, FGD(90), ESP	5	.2855[d] (.1233)	.4670[d] (.2017)	5.820[c] (2.513)	.0404[d] (.0174)	.5033[c] (.2173)
LSC-30 UNC, UNC, SM	B	.2140[e] (.0924)	.7210[e] (.3113)	8.790[c] (3.796)	.2720[e] (.1174)	3.310[c] (1.429)
LEA, UNC, SSS	1	.2140[e] (.0924)	.7210[e] (.3113)	8.790[c] (3.796)	.1209[e] (.0522)	1.471[c] (.6352)
LEA, UNC, FF	2	.2140[e] (.0924)	.7210[e] (.3113)	8.790[c] (3.796)	.0302[e] (.0130)	.3678[c] (.1588)
LEA, DS(50), DS	3	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	.2855[f] (.1233)	.0970[f] (.0419)	1.210[c] (.5225)	.0807[f] (.0348)	1.007[c] (.4348)
LEA, FGD(90), FF	5	.2855[f] (.1233)	.0970[f] (.0419)	1.210[c] (.5225)	.0403[f] (.0174)	.5033[c] (.2173)
HSC-75 UNC, CC, SM	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, SSS	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, ESP	2	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	.5379[e] (.2323)	.9480[e] (.4093)	12.90[c] (5.570)	.1630[e] (.0704)	2.210[c] (.9543)
LEA, FGD(90), ESP	5	.5379[e] (.2323)	.9480[e] (.4093)	12.90[c] (5.570)	.0815[e] (.0352)	1.105[c] (.4771)
LSC-75 UNC, UNC, SM	B	.3300[g] (.1425)	1.200[g] (.5182)	14.60[h] (6.304)	.4511[g] (.1949)	5.490[h] (2.372)
LEA, UNC, SSS	1	.3300[g] (.1425)	1.200[g] (.5182)	14.60[h] (6.304)	.2005[g] (.0866)	2.440[h] (1.054)
LEA, UNC, FF	2	.3300[g] (.1425)	1.200[g] (.5182)	14.60[h] (6.304)	.0502[g] (.0217)	.6100[h] (.2635)
LEA, DS(50), DS	3	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	.5379[e] (.2323)	.2000[e] (.0864)	2.720[c] (1.174)	.1630[e] (.0704)	2.210[c] (.9543)
LEA, FGD(90), FF	5	.5379[e] (.2323)	.2000[e] (.0864)	2.720[c] (1.174)	.0815[e] (.0352)	1.105[c] (.4771)
NG-150 UNC, UNC, UNC	B	.3795[g] (.1638)	.0015[g] (.0006)	.0194[i] (.0083)	.1053[g] (.0454)	.1880[i] (.0811)
LEA/RAP, UNC, UNC	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
DIS-150 UNC, UNC, UNC	B	.3790[g] (.1636)	.8060[g] (.3480)	9.890[i] (4.271)	.0230[g] (.0099)	.2820[i] (.1218)
LEA/RAP, HDS, UNC	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
RES-150 UNC, HDS, UNC	B	.6000[g] (.2591)	2.400[g] (1.036)	29.80[i] (12.87)	.3450[g] (.1489)	4.290[i] (1.852)
LEA, HDS, HDS	1	.4490[g] (.1939)	1.185[g] (.5115)	14.93[i] (6.44)	.1500[g] (.0648)	1.860[i] (.8031)
LEA, HDS, HDS	2	.4490[g] (.1938)	.4495[g] (.1940)	5.60[i] (2.42)	.1500[g] (.0648)	1.860[i] (.8031)
LEA, FGD(90), FGD	3	.8610[e] (.3719)	.9184[e] (.3964)	12.91[c] (5.57)	.2813[e] (.1214)	3.93[d] (1.69)
LEA, FGD(90), ESP	4	.8610[e] (.3719)	.9184[e] (.3964)	12.91[c] (5.57)	.1407[e] (.0607)	1.97[e] (.8503)

TABLE 7-9. (Continued)

Model Boiler	Control Alternative	Maximum Downwind Ambient Air Concentration at Averaging Period $\mu g/m^3$ (10^{-6} gr/dscf)				
		NO_2[o]	SO_2[n]		Particulate[m]	
		Annual Mean	Annual Mean	Max.- 24 Hr.	Annual Mean	Max.- 24 Hr.
HSC-150 UNC, CC, SM	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, SSS	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, CC, ESP	2	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	1.325[e] (.5721)	1.510[e] (.6520)	21.60[c] (9.327)	.2577[e] (.1113)	3.700[c] (1.598)
LEA, FGD(90), ESP	5	1.325[e] (.5721)	1.510[e] (.6520)	21.60[c] (9.327)	.1288[e] (.0556)	1.850[c] (.7988)
LSC-150 UNC, UNC, SM	B	.7940[i] (.3428)	1.500[j] (.6477)	18.70[i] (8.075)	.7613[j] (.3287)	9.544[j] (4.121)
LEA, UNC, SS	1	.6302[j] (.2721)	1.500[j] (.6477)	18.70[i] (8.075)	.2538[j] (.1096)	3.181[i] (1.374)
LEA, UNC, FF	2	.6302[j] (.2721)	1.500[j] (.6477)	18.70[i] (8.075)	.0634[j] (.0274)	.7953[i] (.3434)
LEA, DS(50), DS	3	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mnra[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), FGD	4	1.307[e] (.5644)	.3130[e] (.1352)	4.490[c] (1.939)	.2550[e] (.1101)	3.667[c] (1.584)
LEA, FGD(90), FF	5	1.307[e] (.5644)	.3130[d] (.1352)	4.490[c] (1.939)	.1275[e] (.0550)	1.833[c] (.7918)
RES-400 LEA, FGD(75), FGD	B	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, HDS, HDS	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA, FGD(90), ESP	2	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	.3040[j] (.1313)	4.260[k] (1.839)
HSC-400 LEA, FGD(90)[a], FGD	B	2.120[j] (.9154)	3.640[j] (1.572)	51.00[i] (22.02)	.4500[g] (.1943)	6.600[c] (2.850)
LEA/OFA, FGD(90), FGD	2	2.720[g] (1.174)	2.600[g] (1.123)	38.20[i] (16.49)	.2250[g] (.0972)	3.300[c] (1.425)
LEA/OFA, FGD(90), ESP	3	2.720[g] (1.174)	2.600[g] (1.123)	38.20[i] (16.49)		
LSC-400 LEA, UNC, FF	B	1.140[k] (.4923)	1.940[k] (.8377)	24.10[d] (10.41)	.1630[k] (.0704)	2.030[d] (.8766)
LEA/OFA, DS(50), DS	1	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)	mrna[l] (mrna)
LEA/OFA, FGD(90), FGD	2	2.670[g] (1.153)	.5330[g] (.2301)	7.820[c] (3.377)	.4400[g] (.1900)	6.467[c] (2.792)
LEA/OFA, FGD(90), FF	3	2.670[g] (1.153)	.5330[g] (.2301)	7.820[c] (3.377)	.2200[g] (.0950)	3.233[c] (1.396)

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[a] Partial scrubbing.

[b] 0.3 Downwind distance from stack (km)

[c] 0.5 "

[d] 1.0 "

[e] 1.3 "

[f] 1.0 "

[g] 1.6 "

[h] 0.7 "

[i] 0.8 "

[j] 2.0 "

[k] 3.0 "

[l] Modeling results not available.

[m] National Primary Ambient Air Quality Standards for particulate matter:

Annual Mean 75 μ/m^3 (32.38×10^{-6} gr/dscf)
Maximum - 24 Hr 260 μ/m^3 (112.26×10^{-6} gr/dscf)

[n] National Primary Ambient Air Quality Standards for SO_2:

Annual Artihmetic Mean 80 μ/m^3 (34.54×10^{-6} gr/dscf)
Maximum - 24 Hr 365 μ/m^3 (157.60×10^{-6} gr/dscf)

[o] National Primary Ambient Air Quality Standard for NO_2:

Annual Arithmetic Mean 100 μ/m^3 (43.18×10^{-6} gr/dscf) several of the emission control alternatives presented in Tables 7-1 and 7-2 are not represented in the dispersion analysis because of their subsequent addition to the study after these results were generated.

Table 7-9 presents the maximum downwind ambient air concentrations of NO_x, SO_2 and PM over the same averaging times that are used to define the Primary National Ambient Air Quality Standards (NAAQS). Downwind distances from the stack to the receptor are indicated with footnotes. A footnote to Table 7-9 presents the Primary NAAQS for NO_x, SO_2 and PM. Comparison of these values to the modeling results reported in Table 7-9 shows that the model boilers, located in a pristine atmosphere, comply with the NAAQS, as described in the 1971 Federal Register. For the alternative control levels investigated the dispersion analysis shows that ground level concentrations of NO_x, SO_2, and PM, range from 0.1 to 20 percent of the concentrations specified by the ambient air quality standards.

The dispersion analysis also shows the ambient air impact in going from the baseline control level to a more stringent control level. As an example, for the 44 MW (150 x 10^6 Btu/hr) model boiler burning residual oil, the 24-hour average ground level concentration of SO_2 is reduced by 81 percent in going from the baseline control level of 688 ng/J (1.6 lb/10^6 Btu) to a more stringent emission control level of 129 ng/J (0.3 lb/10^6 Btu). In addition, for the same model boiler, ambient PM concentrations are reduced by 57 percent as the result of a 57 percent decrease in the PM emission level and ambient NO_x impacts are reduced by 25 percent corresponding to a 25 percent decrease in the NO_x emission level.

Results from the dispersion analysis indicate that where flue gas reheat is not applied, the use of wet FGD scrubbers to control SO_2 emissions can have an impact on the ground level concentrations of SO_2, PM, and NO_x. Wet FGD scrubbers cause a cooling of the flue gas which results in reduced plume buoyancy. When plume buoyancy is reduced, dispersion of the pollutants in the upper atmosphere is inhibited and ground level concentration is increased.

To illustrate the effect of reduced plume buoyancy on ground level concentrations, the ground level concentrations of NO_x, SO_2, and PM are compared for the RES-150 model boilers using HDS and FGD to control SO_2 emissions (Alternatives 2 and 3, respectively). NO_x and PM emission rates are the same for both alternatives while the SO_2 emission rates vary by only 6 percent (0.32 lb/10^6 Btu for Alternative 3, 0.30 lb/10^6 Btu for Alternative 2). Table 7-9 shows that when the wet FGD system is used, ground level NO_x, SO_2, and PM concentrations are about 2 times greater than the concentrations associated with using HDS oil. In addition, the modeling results show that the higher ground level concentrations associated with FGD applications occur at receptors which are located close to the stack when compared with the receptor distances where HDS oil is used. It should be noted that the use of FGD does not increase the ground level concentrations of SO_2 or PM over those values that are estimated to represent the current model boiler ambient air impacts (impacts at baseline). However, NO_x concentrations do tend to increase by 40 to 50 percent over baseline with the application of LEA and SCA controls.

7.1.2 Secondary Air Impacts.

Secondary air emissions result from power boilers supplying electricity to the industrial boiler control devices. The power required to operate pollution control equipment will ultimately result in greater emissions at the electric power generation facility.

Tables 7-10 and 7-11 present the estimated incremental NO_x, SO_2, and PM emissions from a coal-fired electric power generation facility supplying power to operate model boiler pollution controls. Natural gas-fired model boilers are not included since virtually no electrical energy is required for pollution control. Incremental NO_x, SO_2, and PM emissions at the power generating facility were calculated using the control device power requirement and assuming that the power boilers comply with the NSPS for utility boilers.[1]

Tables 7-10 and 7-11 show that the emissions caused by auxiliary power generation are very small when compared to the emission reductions from the model boilers that were presented in Section 7.1.1. For example, a 117 MW (400 x 10^6 Btu/hr) model boiler burning high sulfur coal with SO_2 and PM emissions controlled to the most stringent Alternative 3 level would

TABLE 7-10. SECONDARY AIR POLLUTION IMPACTS FOR COAL-FIRED MODEL BOILERS

Model Boiler	Emission Specie	Power Boiler Emissions [Mg/yr (tons/yr)]					
		Baseline	Alt. 1[c]	Alt. 2	Alt. 3	Alt. 4	Alt. 5
HSC-30	NO_x	.12 (.13)	.15 (.17)	.04 (.04)	a	.19 (.21)	.23 (.25)
	SO_2	.17 (.19)	.23 (.25)	.05 (.06)		.28 (.31)	.35 (.38)
	PM	.01 (.01)	.01 (.01)	0 (0)		.01 (.01)	.02 (.02)
HSC-75	NO_x	.30 (.33)	.42 (.46)	.12 (.13)	a	.49 (.54)	.16 (.67)
	SO_2	.45 (.50)	.63 (.69)	.17 (.19)		.74 (.81)	.91 (1.0)
	PM	.02 (.02)	.03 (.03)	.01 (.01)		.03 (.03)	.04 (.04)
HSC-150	NO_x	.61 (.67)	.80 (.88)	.26 (.29)	a	.87 (.96)	1.14 (1.25)
	SO_2	.91 (1.0)	1.20 (1.32)	.39 (.43)		1.31 (1.44)	1.71 (1.88)
	PM	.04 (.04)	.05 (.05)	.02 (.02)		.05 (.06)	.07 (.08)
HSC-400	NO_x	2.73 (3.01)	a	5.08 (5.60)	5.77 (6.35)	b	b
	SO_2	4.10 (4.51)		7.62 (8.39)	8.64 (9.52)		
	PM	.16 (.18)		.31 (.34)	.35 (.38)		
LSC-30	NO_x	.12 (.13)	.15 (.17)	.19 (.21)	.23 (.25)	.19 (.21)	.38 (.42)
	SO_2	.17 (.19)	.23 (.25)	.28 (.31)	.35 (.38)	.28 (.31)	.57 (.63)
	PM	.01 (.01)	.01 (.01)	.01 (.01)	.02 (.02)	.01 (.01)	.03 (.03)
LSC-75	NO_x	.30 (.33)	.38 (.42)	.45 (.50)	.68 (.75)	.45 (.50)	.91 (1.0)
	SO_2	.45 (.50)	.57 (.63)	.68 (.75)	1.03 (1.13)	.68 (.75)	1.36 (1.5)
	PM	.02 (.02)	.03 (.03)	.03 (.03)	.05 (.05)	.03 (.03)	.05 (.06)
LSC-150	NO_x	.61 (.67)	.76 (.84)	.91 (1.0)	1.03 (1.13)	.80 (.88)	.80 (.88)
	SO_2	.91 (1.0)	1.14 (1.25)	1.36 (1.5)	1.53 (1.69)	1.20 (1.32)	1.20 (1.32)
	PM	.04 (.04)	.05 (.05)	.05 (.06)	.06 (.07)	.05 (.05)	.05 (.05)
LSC-400	NO_x	2.12 (2.34)	5.04 (5.55)	4.81 (5.30)	6.94 (7.64)	b	b
	SO_2	3.19 (3.51)	7.56 (8.33)	7.33 (7.95)	10.41 (11.46)		
	PM	.13 (.14)	.30 (.33)	.30 (.32)	.42 (.46)		

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[a] 50% scrubbing not applied since this will not meet the baseline emission limit.

[b] There are no alternatives 4 and 5 for the 117 MW (400 x 10^6 Btu/hr) boilers.

TABLE 7-11. SECONDARY AIR POLLUTION IMPACTS FOR GAS- AND OIL-FIRED MODEL BOILERS

Model Boiler	Emission Specie	Power Boiler Emissions [Mg/yr (tons/yr)]				
		Baseline	Alt. 1	Alt. 2	Alt. 3	Alt. 4
RES-30	NO_x	.17 (.19)	.38 (.42)	.50 (.55)	.46 (.46)	
	SO_2	.25 (.28)	.56 (.62)	.75 (.83)	.69 (.69)	DNA[a]
	PM	.01 (.01)	.02 (.02)	.03 (.03)	.03 (.03)	
RES-150	NO_x	.88 (.97)	1.92 (2.11)	2.46 (2.71)	.72 (.67)	1.03 (1.13)
	SO_2	.32 (.35)	2.88 (3.17)	3.70 (4.07)	1.08 (1.00)	1.53 (1.69)
	PM	.05 (.06)	.12 (.13)	.15 (.17)	.04 (.04)	.06 (.07)
RES-400	NO_x	1.60 (1.76)	5.68 (6.26)	2.18 (2.40)		
	SO_2	2.40 (2.65)	8.51 (9.38)	3.27 (3.60)		
	PM	.10 (.11)	.34 (0.37)	.13 (0.14)		
DIS-30	NO_x	0 (0)	.08 (.09)			
	SO_2	0 (0)	.13 (.14)			
	PM	0 (0)	.01 (.01)			
DIS-150	NO_x	0 (0)	.22 (.24)			
	SO_2	0 (0)	.33 (.37)			
	PM	0 (0)	.01 (.01)			

[a] Data not available (See Energy Impacts Table 7-15).

indirectly result in the following incremental emissions from the power boiler:

NO_x - 5.47 Mg/yr (6.02 tons/yr)
SO_2 - 8.20 Mg/yr (9.03 tons/yr)
PM - 0.3 Mg/yr (0.33 tons/yr)

These power boiler emissions would be offset by the following emission reductions from the 117 MW (400 x 10^6 Btu/hr) coal-fired model boiler.

NO_x - 152.7 Mg/yr (168.2 tons/yr)
SO_2 - 4898 Mg/yr (5394 tons/yr)
PM - 6814 Mg/yr (7504 tons/yr)

A similar relationship between power boiler emissions and model boiler emission reductions is evident for all other model boilers.

7.2 LIQUID WASTE IMPACTS

Water pollution impacts or the need for additional water treatment can result from controlling industrial boiler air emissions if the control technologies used to achieve the various control levels produce aqueous discharge streams. Control of NO_x by combustion modification, as discussed in Chapter 4, does not result in aqueous discharges. Likewise, control of PM or SO_2 emissions by use of hydrodesulfurized fuel oils or low sulfur coal does not result in any waste water streams. Consequently these technologies are not considered further.

Dry particulate controls (ESP, FF, MC) also do not result in water discharges, but incremental water pollution impacts from PM controls can result if the collected particulate material is sluiced to disposal ponds. However, the sluiced ash stream from a PM control device can be treated in existing facilities along with the boiler ash stream, and the water reused.[2]

The control of SO_2 by FGD can result in liquid waste discharges while dry scrubbing processes are designed not to generate liquid wastes. Once-through sodium scrubbing systems (FGD/Na) result in direct liquid discharges of sodium sulfite/sulfate salts. Dual-alkali, lime and limestone FGD systems can be designed on a closed-loop basis so that the only water losses during normal operation occur with the sludge going to landfill. Purging of either of these systems due to water imbalances or other operating upsets, system blowdown to prevent scaling, or operator error will result in discharge of an aqueous waste stream which can be contained and treated. However, during normal operation, there should be no water pollution impact from lime, limestone and dual-alkali (FGD) systems designed on a closed-loop, zero discharge basis.[3]

Since the sodium throwaway (once-through) system is the primary system resulting in liquid discharges, the remainder of this section focuses on the water pollution impacts of the sodium throwaway FGD system. Potential water pollution impacts were assessed by considering the following:

- effluent quantity and characteristics,
- effluent treatment and disposal, and
- applicable regulations.

7.2.1 Effluent Quantities and Characteristics

Aqueous emissions from a sodium throwaway FGD process contain about 5 percent (by weight) dissolved solids.[4] The composition of the dissolved solids will vary depending upon the extent of sulfite oxidation; with the major compounds consisting of sodium sulfate (Na_2SO_4), sodium sulfite (Na_2SO_3), and sodium carbonate (Na_2CO_3). In addition, chlorides and trace elements absorbed from the flue gas will be present in smaller amounts.

The only model boiler using a sodium throwaway FGD control (FGD/Na) is the RES-30 model boiler. This model boiler is typical of oil-field steam generators where the majority of the sodium throwaway systems are used. FGD/Na systems were not considered for other model boilers because potential regulations may limit the discharge of FGD/Na effluents into municipal water treatment facilities. The estimated liquid waste impacts resulting from applying Alternatives 3 and 4 (90 percent SO_2 control) to the RES-30 model boiler are effluent discharge rates of 25.3 liters/min (6.7 gpm). On an annual basis the discharge rate is 8.0×10^6 ℓ/yr (1.88×10^6 gal/yr).

Table 7-12 shows effluent discharge rates for HSC boilers using FGD/Na systems to reduce SO_2 emissions by 90 percent. As can be seen, for a fixed

TABLE 7-12. WATER POLLUTION IMPACTS FOR THE SODIUM THROWAWAY SYSTEM

Model Boiler Heat Input			Effluent Discharge Rate[b]	
MW	(10^6 Btu/hr)	Fuel Type[a]	ℓ/Min	(gpm)
8.8	(30)	HSC	51.0	13.4
22	(75)	HSC	130.8	32.6
44	(150)	HSC	262.8	69.4
117	(400)	Pulverized HSC	702.0	185.0
Average Dissolved Solid Compositions		Na_2SO_3 - 77 percent Na_2SO_4 - 9 percent Na_2CO_3 - 14 percent		

[a] HSC is 3.5% sulfur

[b] Based on 90% removal of SO_2

control level the effluent discharge rate increases directly with the boiler heat input capacity. Therefore, with a 100 percent increase in boiler heat input capacity, (22 MW to 44 MW) the discharge rate could also be expected to increase by approximately 100 percent.

7.2.2 Effluent Treatment and Disposal

The dissolved solids content and pH-imbalances are the two main areas of concern for which treatment may be required for wastes from a sodium scrubbing system. Discharge to an evaporation pond or to an existing centralized wastewater treatment facility is commonly practiced. Of the 102 sodium scrubbings systems in use today, about 80 use evaporation ponds (over 30 of these in conjunction with well injection), and 10 use centralized water treatment for disposal of FGD wastes.[5]

If the scrubber effluents are being discharged directly to a receiving stream, the water quality standards applicable to that stream will govern the degree of treatment required. Also, if the scrubber effluents are discharged to a publicly owned treatment works (POTW), then the pretreatment requirements contained in the guidelines for that POTW will determine the degree of treatment necessary. Treatment methods available to reduce total dissolved solids include: ion exchange, electrodialysis, reverse osmosis, and distillation.[6] Neutralization of the wastewater may be necessary to achieve proper pH. The treatment method employed at a centralized treatment facility will depend upon the characteristics of the industry's process waste streams with which the scrubber effluent is being combined.

Some industries (e.g., textile and paper mills) can use process waste streams containing sodium as a feed to the scrubber. The aqueous stream from the FGD system is then recombined with the industrial process waste streams and discharged to an on-site centralized waste treatment facility.[7] The treatment processes in such a centralized treatment facility vary with the specific industry. Typically, the treatment is designed to remove the dissolved and suspended solids and attain a neutral pH.

The adverse impacts of discharging aqueous scrubber wastes to the environment are potential degradation of the water quality (both surface and ground) of the receiving stream and the subsequent impact on users of that water. Improper treatment or disposal practices can allow aqueous wastes with high total dissolved solids to be introduced into streams and aquifers that may serve as sources of water for other users.

7.2.3 Applicable Regulations

The applicable regulations relative to liquid waste discharge will be governed by the disposal technique being used. Discharges to a surface facility (a receiving stream, centralized industrial wastewater treatment facility or publicly owned treatment works) will have to satisfy the requirements of the Clean Water Act. Disposal by deep-well injection must satisfy requirements of the Safe Drinking Water Act and the Underground Injection Control Program.[8]

If the scrubber effluent is discharged to an on-site centralized industrial wastewater treatment facility and is treated along with other process waste streams, specific effluent standards applicable to the industry with which the boiler facility is associated must be satisfied. The scrubber effluent will be considered a contributing source to the central treatment facility and will be listed as such on the National Pollutant Discharge Elimination System (NPDES) permit for that treatment facility.

When the scrubber effluent is discharged directly to a waterway, the effluent must be treated to meet specific instream water quality standards at the location of the discharge. If the scrubber discharge is directed to a POTW, pretreatment guidelines must be met, so that these effluents do not interfere with the operation and performance of the POTW.

When effluents are being disposed of by well injection, steps must be taken to assure that contamination of any drinking water sources does not occur. The Underground Injection Control Program proposed regulations specify the procedures to be followed to protect any sources of drinking water and specify how those sources of water will be identified.[8]

7.3 SOLID WASTE DISPOSAL IMPACTS

Industrial boiler air pollution control techniques produce two main types of solid wastes: fly ash collected by the PM control devices, and waste solids (both sludge and dry scrubbing products) from the control of SO_2 emissions. No incremental solid waste results from NO_x emission control by combustion modification. In this section, the impacts of the incremental solid wastes produced from PM and SO_2 controls are discussed by considering the following:

- solid waste quantities and characteristics,
- waste treatment and disposal, and
- applicable regulations.

7.3.1 Solid Waste Quantities and Characteristics

The primary constituents of coal fly ash are silicon, aluminum, iron, and calcium, with lesser quantities of magnesium, titanium, sodium, potassium, sulfur, and phosphorus. In addition, fly ash contains trace concentrations of from 20 to 50 elements (depending on the specific coal), including lead, arsenic, and cadmium, and radionuclides of several elements.[9]

Dual alkali scrubber sludges are composed primarily of calcium sulfite/sulfate solids. Also present are dissolved sodium salts and trace elements (e.g., lead, arsenic and cadmium), which may contaminate the groundwaters and surface waters due to runoff and leaching from sludge disposal sites (see Section /.2.3). The chemical composition and concentration of FGD sludge varies with the different coal types used in industrial boilers. When a particulate collection device is not used upstream of the FGD system and the FGD system is being used to control both SO_2 and PM emissions, the trace element concentrations in the scrubber sludge are increased due to the addition of fly ash to the sludge.

The dry solid waste produced from dry scrubbing FGD processes consists primarily of calcium or sodium salts, depending upon the type of alkali used as the SO_2 sorbent. Significant quantities of fly ash will also be present, because the PM collection device is located downstream of the spray dryer and removes fly ash along with the spray dried solids.

Tables 7-13 and 7-14 show the quantities of solid wastes for each of the model boilers equipped with controls that result in a solid waste. Waste production rates are graphically illustrated in Figure 7-1 for coal-fired model boilers. For the ESP, FF, and mechanical collector control techniques, the solid waste quantities presented are the quantities of fly ash collected on a dry basis. For SO_2 control, the quantities of sludge presented are for a FGD system with a sludge quality of 60 percent solids. The solid wastes shown for the dry scrubbing (DS) control consist of fly ash, sulfate/sulfite salts, and unreacted sorbent collected by the fabric filter system downstream of the dry SO_2 scrubbing system. Sludge quantities presented for the combined SO_2/PM systems are based on a sludge concentration of 60 percent solids and include fly ash collected in the scrubber.

Table 7-13 and Figure 7-1 can be used to show the relative increase in solid waste resulting from increasingly stringent control alternatives. For example, the HSC-30 model boiler exhibits more than a 10 fold increase in going from baseline to control Alternative 5, while the LSC-30 model boiler shows about a 5 fold increase. In both cases, this solid waste increase can be attributed primarily to the FGD system applied at the more stringent control Alternatives 4 and 5. In general, increases such as the ones demonstrated by this example can be expected for boilers where no baseline FGD systems are required. This includes all LSC and HSC boilers smaller than 73 MW (250×10^6 Btu/hr), and RES boilers smaller than 73 MW. In addition, Table 7-13 illustrates that where FGD is used to collect fly ash as well as SO_2, (i.e., Alternative 4 for coal-fired boilers, Alternative 3 for oil-fired boilers) overall solid waste loading will increase over systems that collect fly ash by dry collection methods (i.e., Alternative 5 for coal-fired boilers, Alternative 4 for oil-fired boilers). This is a direct result of the water associated with the fly ash collected in a wet FGD system. For the combined SO_2/PM FGD systems, 80 percent of the total fly ash is removed with an upstream mechanical collector, while the remaining fly ash is collected in the FGD system to meet the PM emission limit of 43 ng/J (0.1 lb/10^6 Btu). The fly ash collected by the FGD unit results in a solid waste that is 60 percent solids (40 percent water). This additional

TABLE 7-13. SOLID WASTE IMPACTS FROM COAL-FIRED MODEL BOILERS

Model Boiler	Type of Solid Waste	Amount of Solid Waste, Mg/yr (ton/yr)[a] Baseline	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5
HSC-30	Fly Ash	130 (143)	145 (160)	155 (171)		122[h] (134)	155 (171)
	Sludge				f	1539[b] (1695)	1489 (1640)
	Total	130 (143)	145 (160)	155 (171)		1661 (1829)	1644 (1811)
HCS-75	Fly Ash	326 (359)	362 (399)	388 (427)		303[h] (334)	388 (427)
	Sludge				f	3907[b] (4302)	3780 (4163)
	Total	326 (359)	362 (399)	388 (427)		4210 (4636)	4168 (4590)
HSC-150	Fly Ash	1867 (2058)	2012 (2216)	2065 (2274)		1638[h] (1804)	2065 (2274)
	Sludge				f	8182[b] (9009)	7500 (8260)
	Total	1867 (2058)	2012 (2216)	2065 (2274)		9820 (10815)	9565 (10534)
HSC-400	Fly Ash	6767 (7452)		5414[h] (5961)	6815 (7505)		
	Sludge	12560 (13832)	f	22420[b] (24686)	20164 (22207)	g	g
	Total	19327 (21284)		27834 (30648)	26979 (29712)		
LSC-30	Fly Ash	71 (78)	86 (95)	97 (107)	161[c,d] (177)	74[h] (81)	97 (107)
	Sludge					323[b] (356)	291 (321)
	Total	71 (78)	86 (95)	97 (107)	161[c,d] (177)	397 (437)	288 (317)
LSC-75	Fly Ash	179 (197)	215 (237)	242 (267)	640[c,d] (704)	186[h] (204)	242 (267)
	Sludge					799[b] (880)	721 (794)
	Total	179 (197)	215 (237)	242 (267)	640[c,d] (704)	985 (1085)	963 (1061)
LSC-150	Fly Ash	1090 (1202)	1235 (1360)	1289 (1420)	1873[c,d] (2063)	1017[h] (1120)	1289 (1420)
	Sludge					2028[b] (2233)	1605 (1768)
	Total	1090 (1202)	1235 (1360)	1289 (1420)	1873[c,d] (2063)	3044 (3352)	2894 (3187)
LSC-400	Fly Ash	4200 (4625)	4876[c,e] (5370)	3360[h] (3700)	4248 (4678)		
	Sludge			10606[b] (11678)	9206 (10139)	g	g
	Total	4200 (4625)	4876[c,e] (5370)	13966 (15377)	13454 (14817)		

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[a] Fly Ash - Mg/yr (ton/yr), dry basis; Sludge - Mg/yr (ton/yr) @60 percent solids.

[b] Scrubber also removes fly ash. This fly ash is included with the sludge @60 percent solids.

[c] Total fly ash and alkali salts.

[d] Sodium sorbent.

[e] Lime sorbent.

[f] 50 percent removal alternative not applicable for HSC boilers since this removal would not meet baseline emission limit.

[g] No alternative 4 and 5 for 117 MW boilers.

[h] 80% of the total fly ash is collected dry by a mechanical collector upstream of the scrubber.

TABLE 7-14. SOLID WASTE IMPACTS FROM OIL-FIRED MODEL BOILERS

Model Boiler	Type of Solid Waste	Amount of Solid Waste, Mg/yr (tons/yr)^{a}				
		Baseline	Alt. 1	Alt. 2	Alt. 3	Alt. 4
RES-30	Fly Ash	c	c	c	c	11.8 (13.0)
	Sludge					
	Total					11.8 (13.0)
RES-150	Fly Ash	c	c	c		59.1 (65.1)
	Sludge				3821 (4208)	3756 (4137)
	Total				3821 (4208)	3815 (4202)
RES-400	Fly Ash	91^{d} (100)^{d}	91^{d} (100)^{d}	157.6 (173.6)		
	Sludge	8440^{b} (9296)^{b}	10120^{b} (11147)	10082 (11104)		
	Total	8531 (9397)	10211 (11247)	10240 (11278)		

[a] Fly Ash - Mg/yr (ton/yr); Sludge - Mg/yr (ton/yr) @60% solids.

[b] Fly Ash included @60% solids.

[c] No solid wastes generated.

[d] 80% of total fly ash is removed in an upstream mechanical collector.

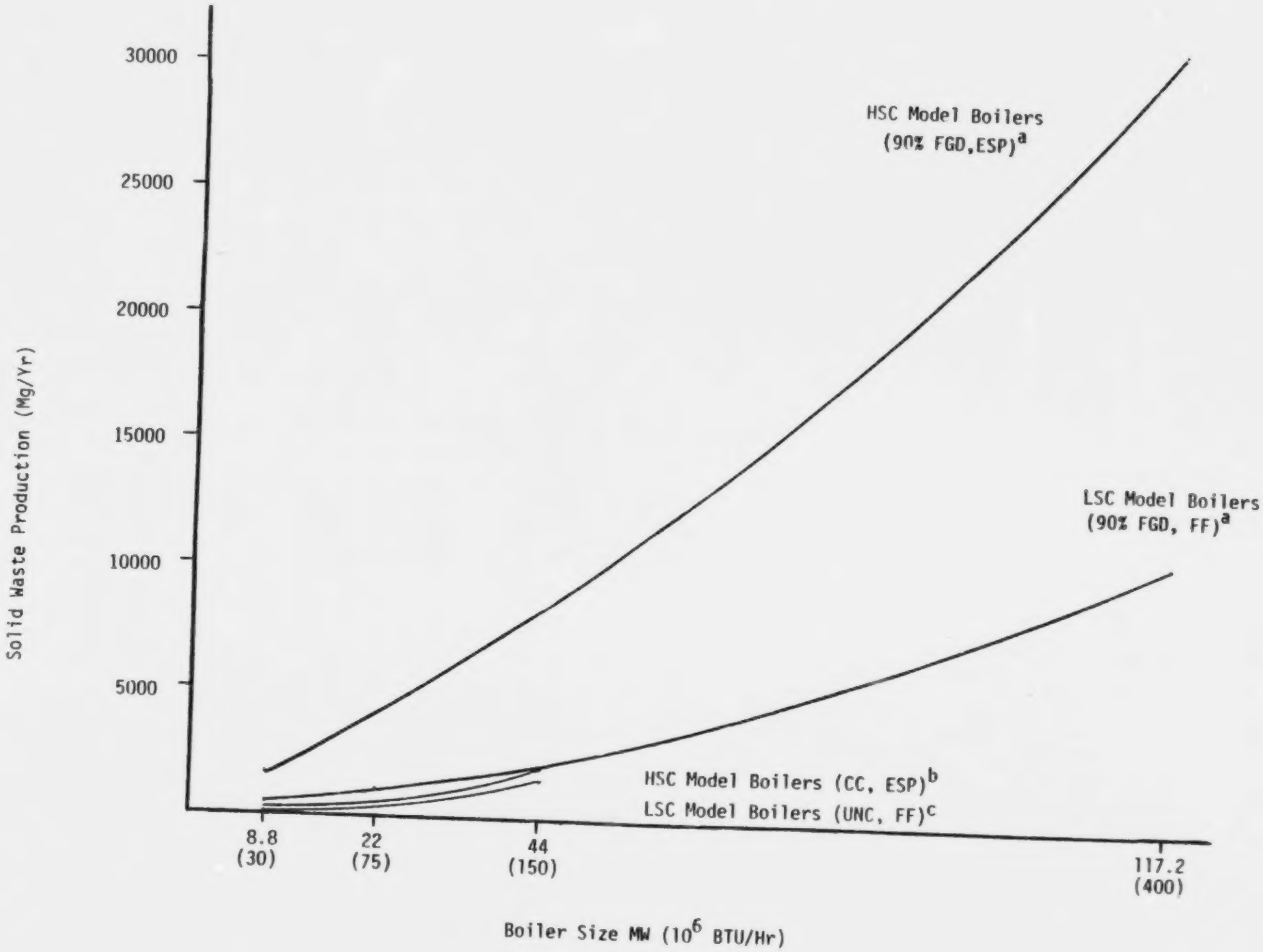

Figure 7-1. Solid Waste Production (Fly Ash and Sludge)

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a) 90% SO_2 removal via Double Alkali FGD
b) SO_2 control via compliance coal, Particulate control via Electrostatic Precipitator.
c) Uncontrolled SO_2, Particulate control via Fabric Filter

water increases the solid waste loading over that resulting from systems that accumulate a dry solid waste.

Figure 7-1 shows that where no FGD systems are required (PM control by SSS/DM, FF, ESP), percent increases over baseline of from 10 to 40 percent are typical for coal-fired boilers. The parabolic shape of the curves shown in Figure 7-1 can be attributed to the nonlinear increase with respect to boiler size in collectable particulate emissions from coal-fired model boilers. This can be seen in Table 7-1 where the uncontrolled emission rates from spreader stokers and pulverized coal units are greater than those from underfeed and chaingrate units, on a $lb/10^6$ Btu basis. It should be noted that these curves are simplified somewhat and as such, should be used to illustrate solid waste loading trends only. Any one curve is actually a set of discontinuous straight lines, with the slopes of these lines increasing with boiler size. The discontinuity occurs at the boiler sizes that correspond to a change in boiler type (i.e., chaingrate to spreader stoker) and subsequent change in uncontrolled particulate emissions.

7.3.2 Waste Treatment and Disposal

Ponding and landfilling are currently the primary methods used for disposing of collected fly ash. An alternative to landfilling is the commercial utilization of fly ash in road embankments, concrete mixture, and sludge stabilization.[10] Current Federal, State and local regulations would govern the disposal practices at the landfills.

Solid wastes from spray dryers (dry scrubbing) may be handled in the same manner as fly ash. Off-site landfilling has been selected as the disposal method for the first two dry scrubbing systems installed on industrial boilers.[11]

The main sludge disposal options for wet FGD systems include ponding and landfilling. Ponding is the simpler of the two methods, but is potentially more harmful to the environment than landfilling. Ponding involves slurrying the sludge to a pond, allowing it to settle and pumping the supernatant liquor either to a treatment process or back to the facility for reuse. Because there is always a hydraulic head on the waste in the bottom of the pond, the potential for leachates reaching ground-water sources beneath the pond is greater than for a landfill. Use of the pond area may be limited after disposal ceases, mainly because of the poor load bearing capabilities of the sludge compared to the original soil structure.[12]

Landfill disposal of FGD wastes in a specially prepared site requires some processing of the wet scrubber sludge (either stabilization or fixation) to obtain a soil-like material that may be loaded, transported and placed as fill. Stabilization refers to the addition of fly ash or other similar material to the sludge to produce only physical changes without any chemical reactons. Fixation is a type of a stabilization which involves the addition of reagents (such as lime) to cause chemical reactions with the sludge.[13] The objective of these treatment methods is to increase the load bearing capacity of the raw sludge and to decrease the permeability and correspondingly the mass transport rate of contaminants leaching out of the sludge.[14]

Proper design of both ponds and landfills is required to assure minimum environmental impact of the solid waste disposal. Contaminants that are contained in ponds and landfills or accidentally spilled on the surface can enter ground-water systems by leakage or leaching. As the term implies, leakage refers to migration of fluids that are deposited on the surface to the subsurface. Leakage is of more concern for ponds and spills than landfills. Leaching, on the other hand, denotes the introduction of water (usually infiltrating precipitation) into the waste after it has been landfilled, so that contaminants are dissolved and elutriated or leached out of the solid material.

Transport of trace elements and other potential pollutants from the disposal site via leaching or run off is determined by many factors, including: (1) the chemical form and concentration of the potential pollutant in the waste, (2) the permeability, sorption capacity, and porosity of the substrate, (3) soil and leachate pH, (4) the permeability and porosity of the waste, (5) the proximity of the disposal site to the ground-water table and/or surface water, (6) the presence or absence of clay or plastic liners or other methods of enclosing the wastes in materials of low permeability, and (7) climatic factors such as precipitation, temperature, and relative humidity.[15] However, if a landfill site is properly designed and operated, these leaching and runoff problems can be averted and the landfill area eventually reused either for recreational or building use purposes.[16]

7.3.3 Waste Disposal Regulations

At the present time, the regulations governing solid waste disposal are not fully defined. EPA recently (May 2, 1980) issued Phase I final RCRA regulations covering the framework for management of solid wastes.[17] In addition, Congress is currently considering legislation that would exempt certain "special wastes" (as defined in the proposed regulations) from the possibility of being classified as hazardous until more data are gathered about their characteristics (2 to 3 years).[17]

The Phase I RCRA regulations exempt fly ash, bottom ash, slag, and air pollutant emission control sludge produced in the combustion of fossil fuels from consideration as hazardous wastes. This exemption applies to industrial boiler FGD sludges.

Since the wastes are currently exempt from hazardous waste regulations, they may be considered non-hazardous. Non-hazardous waste disposal management and techniques will be governed by Section 4004 of RCRA. This section requires states to implement disposal programs that will protect the environment (especially ground water) from contamination. EPA has also published Landfill Disposal of Solid Waste, Proposed Guidelines that will act as a guide to the states as to what their disposal management programs should contain.[18]

Disposal of non-hazardous wastes will require at a minimum that a clay liner be used at the disposal site, that daily cover be applied, that access to the site be controlled, that ground-water quality at the site boundary be monitored, and that a final impermeable cover be placed and revegetation occur.[18] These activities are required, primarily, to protect ground water in the disposal area.

7.4 ENERGY IMPACT OF CONTROL TECHNOLOGIES

All control systems used for PM, and SO_2 emission control will require electrical energy. The major portion of the electrical energy is needed to operate the fans installed to overcome the pressure drop across control systems. Lesser amounts of electrical energy are needed for motors that operate the pumps in wet scrubbing systems and bag cleaning mechanisms in fabric filters. For ESP's, energy is also required to create the corona discharge and to run auxiliary equipment such as collection plate rappers.[19,20] Use of HDS cleaned oils results in energy penalties in the form of power requirements at the HDS facility. These energy requirements include demands for electricity, fuel and steam at the hydrogen plant, oil heaters and miscellaneous processes. Use of low excess air (LEA) for NO_x emission control results in improved boiler efficiency, and therefore an overall net gain in energy for the industrial boiler. However, use of other NO_x combustion modifications techniques [flue gas recirculation (FGR), and staged combustion air (SCA)] may result in energy penalties.[21] The energy requirements for combined SO_2/PM systems include energy for operating the wet scrubber along with the energy associated with slurry pumping and sludge handling. Combined SO_2/PM systems use venturi scrubber configurations with an estimated pressure drop of 5 kPa (20 inches of water).

Table 7-15 shows the annual energy demand of the control devices associated with each model boiler. The steam and electrical demands are expressed in thermal megawatts and 10^6 Btu/hr of net heat input to the model boiler. Control device energy demands were derived from information supplied in the Individual Technology Assessment Reports for each control method. A 33 percent heat to electrical energy conversion efficiency was assumed.

Hydrodesulfurization of fuel oil is shown to be the most energy intensive control technology considered. For all residual oil-fired boilers, 2.4 percent of the boiler heat input is required to achieve 50 percent sulfur reduction while 5.8 percent is required for 75 percent reduction and 8.0 percent is required to achieve 90 percent reduction. In comparison, for

TABLE 7-15. MODEL BOILER ENERGY REQUIREMENTS

Model Boiler[a]	Control Alternative	Energy Demand MW$_t$ (10^6 Btu/hr)[b]			Percent of Boiler Heat Input			
		NO$_x$	SO$_2$	PM	NO$_x$	SO$_2$	PM	Total
HSC-30 - Unc, CC, SM	Baseline			.03 (.10)			.34	.34
Unc, CC, SSS	1			.04 (.14)			.45	.45
Unc, CC, ESP	2			.005 (.015)			.06	.06
Unc, FGD (90), FGD[i]	4		.11 (.37)	c		1.25	c	1.25
Unc, FGD (90), ESP	5		.05 (.17)	.009 (.027)		.57	.10	.67
HSC-75 - Unc, CC, SM	Baseline			.08 (.27)			.36	.36
Unc, CC, SSS	1			.11 (.37)			.50	.50
Unc, CC, ESP	2			.03 (.10)			.14	.14
Unc, FGD (90), FGD[i]	4		.27 (.92)	c		1.23	c	1.23
Unc, FGD (90), ESP	5		.13 (.44)	.03 (.10)		.59	.14	.73
HSC-150 - SCA, CC, SM	Baseline	0		.16 (.54)			.36	.36
SCA, CC, SSS	1	0		.21 (.71)			.48	.48
SCA, CC, ESP	2	0		.07 (.24)			.16	.16
SCA, FGD (90), FGD[i]	4	0	.53 (1.80)	c		1.21	c	1.21
SCA, FGD (90), ESP	5	0	.23 (.78)	.07 (.24)		.52	.16	.68
HSC-400 - LEA, FGD (90), FGD[i]	Baseline	0[g]	.54 (1.84)	.11 (.33)		.46	.09	.55
SCA, FGD (90), FGD[i]	2	.73 (2.48)	1.26 (4.28)	c	.30	1.08	c	1.38
SCA, FGD (90), ESP	3	.73 (2.48)	.61 (2.07)	.14 (.42)	.30	.52	.19	.94
LSC-30 - Unc, Unc, SM	Baseline			.03 (.10)			.34	.34
Unc, Unc, SSS	1			.04 (.14)			.45	.45
Unc, Unc, FF	2			.05 (.17)			.57	
Unc, DS (50), DS[i]	3		.15 (.51)	c		1.70	c	1.70
Unc, FGD (90), FGD[i]	4		.11 (. 37)	c		1.25	c	1.25
Unc, FGD (90), FF	5		.05 (.17)	.05 (.17)		.57	.57	1.14
LSC-75 - Unc, Unc, SM	Baseline			.08 (.27)			.36	.36
Unc, Unc, SSS	1			.10 (.34)			.45	.45
Unc, Unc, FF	2			.12 (.41)			.55	.55
Unc, DS (50), DS[i]	3		.32 (1.09)	c		1.45	c	1.45
Unc, FGD (90), FGD[i]	4		.26 (.88)	c		1.18	c	1.18
Unc, FGD (90), FF	5		.12 (.41)	.12 (.41)		.55	.55	1.10
LSC-150 - Unc, Unc, SM	Baseline			.16 (.54)			.36	.36
SCA, Unc, SSS	1	0		.20 (.68)			.45	.45
SCA, Unc, FF	2	0		.24 (.82)			.55	.55
SCA, DS (50), DS[i]	3	0	.60[h] (2.04)[h]	c		1.36	c	1.36
SCA, FGD (90), FGD[i]	4	0	.48 (1.63)	c		1.10	c	1.10
SCA, FGD (90), FF	5	0	.21 (.71)	.24 (.82)		.48	.55	1.03
LSC-400 - LEA, Unc, FF	Baseline	0[g]		.56 (1.90)			.48	.48
SCA, DS (50), DS[i]	1	.73 (2.48)	1.35 (4.59)	c	.62	1.15	c	1.77
SCA, FGD (90), FGD[i]	2	.73 (2.48)	1.21 (4.11)	c	.62	1.03	c	1.41
SCA, FGD (90), FF	3	.73 (2.48)	.54 (1.84)	.56 (1.90)	.62	.46	.48	1.56

TABLE 7-15. (Continued)

Model Boiler[a]	Regulatory Alternative[b]	Energy Demand MW_t (10^6 Btu/hr)			Percent of Boiler Heat Input			
		NO_x	SO_2	PM	NO_x	SO_2	PM	Total
RES-30 - Unc, HDS, Unc	Baseline		.21[d,f] (.74)[d,f]			2.4		2.4
LEA, HDS, HDS	1	0[g]	.51[d,f] (1.79)[d,f]	c		5.8	c	5.8
LEA, HDS, HDS	2	0[g]	.70[d,f] (2.45)[d,f]	c		8.0	c	8.0
LEA, FGD (90)-MA, FGD[i]	3	0[g]	.08 (.27)	c		.88	c	.88
LEA, FGD (90)-MA, ESP	4	0[g]	.03 (.10)	DNA[e]		.37	DNA[e]	
RES-150 - Unc, HDS, Unc	Baseline		1.06[d,f] (3.71)[d,f]			2.4		2.4
LEA, HDS, HDS	1	0[g]	2.55[d,f] (8.93)[d,f]	c		5.8	c	5.8
LEA, HDS, HDS	2	0[g]	3.52[d,f] (12.32)[d,f]			8.0	c	8.0
LEA, FGD (90), FGD[i]	3	0[g]	.55 (1.85)	c		.88	c	.88
LEA, FGD (90), ESP	4	0[g]	.16 (.54)	.11 (.37)		.36	.25	.61
RES-400 - LEA, FGD[j], FGD[i]	Baseline	0[g]	.36 (1.22)	c		.31	c	.31
LEA, FGD (90), FGD[i]	1	0[g]	.99 (3.33)	c		.85	c	.85
LEA, FGD (90), ESP	2	0[g]	.38 (1.28)	DNA[e]		.32	DNA[e]	
DIS-36 - Unc, Unc, Unc	Baseline							0
LEA, HDS, Unc	1	0[g]	.10[d] (.34)[d]			1.14		1.14
DIS-150 - Unc, Unc, Unc	Baseline							0
LEA/RAP, HDS, Unc	1	0[g]	.47[f] (1.59)[f]			1.14		1.14
NG-30 - Unc, Unc, Unc	Baseline							0
LEA, Unc, Unc	1	0[g]						
NG-150 - Unc, Unc, Unc	Baseline							
LEA/RAP, Unc, Unc	1	0[g]						0

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[a] Nomenclature definitions can be found in Section 6.3

[b] Steam and electricity demands are expressed as net heat input to the model boiler.

[c] Included in SO_2 demand or percent.

[d] Includes heater and hydrogen plant demands.

[e] Data not available.

[f] 3.4% S feedstock for residual and 0.5% feedstock for distillate.

[g] When LEA control is applied to uncontrolled boilers, a small increase in fuel efficiency is realized. The purpose of this table is to present energy penalties associated with various control techniques, and therefore, the energy penalty shown for LEA is zero. RAP tends to reduce efficiency. Therefore, where LEA/RAP are used together the effects are balanced.

[h] Sodium alkali.

[i] Venturi type FGD used for combination SO_2/PM control.

[j] 75% SO_2 removal.

a wet FGD system to achieve 90 percent control, about 0.5 percent of the boiler heat input is required.

Combined SO_2/PM control techniques are the second most energy intensive systems considered. Across the coal-fired boiler size range, energy demands range from 1.03 to 1.25 percent of the boiler heat input for combined systems using venturi-type double alkali scrubbers (Alternative 4), and 1.15 to 1.70 percent for boilers using dry scrubbing systems (Alternative 3). In general, the energy requirements for combined SO_2/PM systems exceed the requirements for model boilers using separate SO_2 and PM controls (e.g., FGD for SO_2, FF for PM). This increase in energy demand is a result of the 5 kPa (20 inches of water) gas-side pressure drop assumed for combined systems, compared to an overall 3 kPa (12 inches of water) pressure drop assumed for the FGD tray type scrubbers with fabric filter particulate control.

Table 7-15 shows that electrostatic precipitators (ESP) require less energy to maintain the corona, overcome system pressure drop and operate plate rappers, than fabric filter systems require for fan and bag cleaning operations. For example, over the model boiler size range, the energy required to operate the ESP at control Alternative 5 [22 ng/J (0.05 lb/10^6 Btu)] ranges from 0.10 to 0.19 percent of the boiler heat input for all HSC boilers, while 0.48 to 0.57 percent is required to operate the fabric filter systems on all LSC boilers. At the less stringent Alternative 2 [43 ng/J (0.1 lb/10^6 Btu)], the energy required to operate ESP's on HSC boilers ranges from 0.06 to 0.16 percent of the boiler heat input, while the energy demand from fabric filter systems on LSC boilers ranges from 0.55 to 0.57 percent.

In conclusion, application of the control alternatives to the model boilers may require less than a total of 2 percent of the boiler heat input to achieve the respective control levels. The exceptions to this are the control alternatives where HDS is applied. Energy requirements for HDS range from 2.4 to 8.0 percent of the boiler heat input.

7.5 OTHER IMPACTS

An increase in noise at the industrial boiler site is expected as a result of the operation of the various control techniques. For FGD's, the higher level of noise would result from fans, pumps, and agitators. For ESPs, the higher noise levels are due to the fans, pumps, compressors, electrode rappers, etc. For FF's, the bag cleaning mechanisms result in increased noise levels. Noise-abatement techniques, such as design changes (redesign of cams, gears, and housings, or provision for vibration absorption), use of absorbing materials placed on walls to absorb sound after it has been generated, and sound barriers or silencers for fans should mitigate the increased noise levels effectively.

7.6 OTHER ENVIRONMENTAL CONCERNS

7.6.1 Long-Term Gains/Losses

Increased emission control of the air pollutants resulting from the operation of industrial boilers would result in reduced air emissions and increased energy, water (if sodium scrubbing systems are used), and solid-waste impacts. The solid-waste and water impacts are mitigated by other EPA regulatory programs. The long-term gains achieved result from reducing PM, SO_2, NO_x, trace metals, radionuclides, inhalable particulates, and POM emissions to the ambient air. Another important long-term benefit will be the application of control technology which makes possible the use of coal in an environmentally acceptable manner.

7.6.2 Environmental Impact of Delayed Standard

As analyzed in Section 7.1, there are significant air quality benefits achieved by emission reductions at the alternative control levels compared to baseline emissions. Large quantities of pollutants are reduced and a significant incremental ambient air quality benefit is achieved. Therefore, the impact of a delayed standard would be negative to the extent that the incremental benefit discussed in Section 7.1 would not be achieved as long as the standard was delayed.

7.7 REFERENCES

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8.0 COSTS

This chapter presents an analysis of the cost impacts of various control alternatives applied to industrial boilers. The costs associated with uncontrolled boilers and emission control systems are evaluated for the model boilers described in Chapter 6. The emphasis is to quantify the individual boiler cost impacts associated with control of NO_x, SO_2, and PM to various emission levels. In addition to this cost impact analysis, an analysis of the economic impacts of various emission control levels on boiler users, boiler manufacturers, and emission control system vendors is presented in Chapter 9. A further analysis of regional and national cost impacts using the Industrial Fuel Choice Analysis Model (IFCAM) is presented in a separate report.[1] The IFCAM analysis accounts for regional variations in projected fossil fuel prices, impacts of national energy policy, and the impacts of local, State, and Federal air quality regulations to generate aggregate economic impacts on the industrial boiler population. Chapter 10 describes the IFCAM methodology and summarizes the major results.

The cost analysis presented in this chapter provides an individual boiler analysis of the cost impacts of various control alternatives. Total capital and annualized costs are presented individually, and relative to the uncontrolled boiler case and the baseline case. The uncontrolled case is defined as a new boiler without any emission controls while the baseline case is defined as a new boiler with controls designed to meet the highest level of emissions expected under the mix of existing regulations (see Chapter 6).

The following sections present the methodology used to develop and analyze the cost impacts for various control technologies. Results are presented as a function of boiler type and size, fuel type, and control alternative. Cost impacts for emerging technologies are presented in Appendix E. Costs for emerging technologies are based on limited cost data since these technologies have not generally been commercially applied to full-scale industrial boilers. As such, the costs presented for emerging technologies in Appendix E should not be considered as accurate as the costs presented in this chapter.

All costs are reported in June 1978 dollars. The costs presented in this chapter do not include costs of emission testing, compliance, monitoring, and reporting that may be incurred under the control alternatives. These costs are addressed in a separate report.[2]

8.1 COSTING APPROACH

The cost impacts of control alternatives, including the baseline alternative, were assessed using the concept of model boilers. As discussed in Chapter 6, model boilers are combinations of standard boilers and particulate matter (PM), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) control methods designed to meet specified emission levels. Cost impacts for each model boiler were calculated in terms of:

- capital costs of boilers and control systems (capital investment required),
- annualized costs of boilers and control systems (annual operation and maintenance costs plus capital related charges),
- incremental capital and annual costs for boilers and control systems over the uncontrolled and baseline alternatives.

The model boilers selected in Chapter 6 for analysis of the cost, energy, and environmental impacts of control technologies are shown in Tables 8.1-1 and 8.1-2 (emerging technologies are addressed in Appendix E). Table 8.1-3 defines the abbreviations used to denote the various control systems. Boilers represented by alternatives 1 thru 5 were selected to allow evaluation of the impacts of NO_x, SO_2, and PM controls across a range of boiler types and sizes, fuel types, and emission control methods.

Cost impacts were analyzed for boilers firing natural gas (NG), distillate fuel oil (DIS), residual fuel oil (RES), low sulfur coal (LSC) and high sulfur coal (HSC). The range of costs developed for boilers firing

TABLE 8.1-1. COAL-FIRED MODEL BOILERS

Standard Boiler[f]	Control Alternative	Emission Levels or Removal Requirements ng/J (lb/10^6Btu)			Control Methods[e]		
		NO_x	SO_2	PM	NO_x	SO_2	PM
HSC-30 HSC-75 HSC-150	B	151-271(0.33-0.63)[c]	1076 (2.5)	172-258 (0.40-0.60)[c]	Unc	CC	SM
	1	215(0.5)	860 (2.0)	86 (0.2)	SCA[b]	CC	SSS
	2	215(0.5)	860 (2.0)	22 (0.05)	SCA[b]	CC	ESP
	3	215(0.5)	50% Removal	43 (0.1)	a	a	a
	4	215(0.5)	90% Removal	43 (0.1)	SCA[b]	FGD	FGD/PM
	5	215(0.5)	90% Removal	22 (0.05)	SCA[b]	FGD	ESP
LSC-30 LSC-30 LSC-150	B	151-271(0.33-0.63)[c]	1076 (2.5)	172-258 (0.40-0.60)[c]	Unc	Unc	SM
	1	215 (0.5)	860 (2.0)	86 (0.2)	SCA[b]	Unc	SSS
	2	215 (0.5)	860 (2.0)	22 (0.05)	SCA[b]	Unc	FF
	3	215 (0.5)	50% Removal	43 (0.1)	SCA[b]	DS	DS/PM
	4	215 (0.5)	90% Removal	43 (0.1)	SCA[b]	FGD	FGD/PM
	5	215 (0.5)	90% Removal	22 (0.05)	SCA[b]	FGD	FF
HSC-400	B	301 (0.7)	516 (1.2)	43 (0.1)	LEA	FGD[d]	FGD/PM
	1	258 (0.6)	50% Removal	43 (0.1)	a	a	a
	2	258 (0.6)	90% Removal	43 (0.1)	SCA	FGD	FGD/PM
	3	258 (0.6)	90% Removal	22 (0.05)	SCA	FGD	ESP
LSC-400	B	301 (0.7)	516 (1.2)	43 (0.1)	LEA	Unc	FF
	1	258 (0.6)	50% Removal	43 (0.1)	SCA	DS	DS/PM
	2	258 (0.6)	90% Removal	43 (0.1)	SCA	FGD	FGD/PM
	3	258 (0.6)	90% Removal	22 (0.05)	SCA	FGD	FF

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[a] 50% SO_2 removal alternative not applicable for HSC standard boilers since this removal would not meet baseline emission level. Therefore, no model boiler is analyzed for this alternative.

[b] SCA required on 44 MW (150 x 10^6 Btu/hr) size only; smaller boilers meet NOx level without control.

[c] Baseline emissions depend on boiler size and type (see **Chapter 6 and Chapter 7**).

[d] 78.9% SO_2 removal efficiency required at baseline.

[e] Abbreviations defined in Table 8.1-3. Unc (uncontrolled) indicates no control system is required to meet emission levels.

[f] Alternatives shown define model boilers for each standard boiler. For example, six model boilers are defined for HSC-30, six are defined for HSC-75, etc.

TABLE 8.1-2. OIL- AND GAS-FIRED MODEL BOILERS

Standard Boiler[c]	Control Alternative	Emission Levels or Removal Requirements ng/J (lb/10^6Btu)			Control Methods[b]		
		NO_x	SO_2	PM	NO_x	SO_2	PM
RES-30 RES-150	B	172 (0.4)	688 (1.6)	99 (0.23)	Unc	HDS (1.6)	Unc
	1	129 (0.3)	344 (0.8)	43 (0.1)	LEA	HDS (0.8)	HDS/PM
	2	129 (0.3)	129 (0.3)	43 (0.1)	LEA	HDS (0.3)	HDS/PM
	3	129 (0.3)	90% Removal	43 (0.1)	LEA	FGD[a]	FGD/PM
	4	129 (0.3)	90% Removal	22 (0.05)	LEA	FGD[a]	ESP
RES-400',	B	129 (0.3)	344 (0.8)	43 (0.1)	LEA	FGD[d]	FGD/PM
	1	129 (0.3)	90% Removal	43 (0.1)	LEA	FGD	FGD/PM
	2	129 (0.3)	90% Removal	22 (0.05)	LEA	FGD	ESP
DIS-30	B	52 (0.12)	219 (0.51)	6 (0.015)	Unc	Unc	Unc
	1	43 (0.1)	129 (0.3)	6 (0.015)	LEA	HDS (0.3)	Unc
DIS-150	B	104 (0.24)	219 (0.51)	6 (0.015)	Unc	Unc	Unc
	1	86 (0.20)	129 (0.3)	6 (0.015)	LEA/RAP	HDS (0.3)	Unc
NG-30	B	52 (0.12)	0.43 (0.001)	4.3 (0.01)	Unc	Unc	Unc
	1	43 (0.1)	0.43 (0.001)	4.3 (0.01)	LEA	Unc	Unc
NG-150	B	104 (0.24)	0.43 (0.001)	4.3 (0.01)	Unc	Unc	Unc
	1	86 (0.20)	0.43 (0.001)	4.3 (0.01)	LEA/RAP	Unc	Unc

[a] Double alkali scrubbing (FGD) used on 44 MW (150 x 10^6 Btu/hr), sodium throwaway (FGD/Na) used on 8.8 MW (30 x 10^6 Btu/hr).

[b] Abbreviations defined in Table 8.1-3. Unc (uncontrolled) indicates no control system is required to meet emission levels.

[c] Alternatives shown define model boilers for each standard boiler. For example, five model boilers are defined for RES-30, five for RES-150, etc.

[d] 75% removal efficiency required at baseline.

TABLE 8.1-3. ABBREVIATIONS FOR CONTROL METHODS

NO_x Control Methods
SCA - Staged combustion air (overfire air) used in combination with LEA
LEA - Low excess air
RAP - Reduced air preheat

SO_2 Control Methods
CC - Compliance coal[a]
FGD - Double alkali scrubbing flue gas desulfurization (90% removal unless noted)
FGD/Na - Sodium throwaway flue gas desulfurization (90% removal)
DS - Dry scrubbing (50% removal) using lime spray drying
HDS(x) - Hydrodesulfurized oil (x percent sulfur)

PM Control Methods
SM - Single mechanical collector (multitube cyclone)
SSS - Sidestream separator
ESP - Electrostatic precipitator
FF - Fabric filter
FGD/PM - Particulate removal via FGD scrubber
DS/PM - Particulate removal via DS fabric filter
HDS/PM - Particulate removal via low ash HDS cleaned oil

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[a] Compliance coal is defined as a coal with a sulfur content allowing an SO_2 emission limit to be met without control. The actual sulfur content depends on the emission limit (see Table 8.1-9).

these fuels are expected to illustrate the range of control costs that boiler operators could experience.

8.1.1 Cost Bases

Capital investment and annual operating and maintenance (O&M) costs were calculated for each model boiler and its associated control method(s). In general, these cost calculations were carried out using a variety of "cost algorithms" developed for boiler and control method cost estimation. Each algorithm represents a particular boiler or control method cost component as a algebraic function of key system specifications. A separate report documents all model boiler costing algorithms and other background data.[2] Table 8.1-4 summarizes the various sources of information used to develop costs.

The boiler specifications presented in Chapter 6 (Tables 6-3 thru 6-7) provide the specifications required to cost boiler systems. In addition, a number of control device specifications are required in order to cost control devices. Table 8.1-5 lists the general specifications for the control devices evaluated. These specifications are typical for industrial boiler control devices currently in use.

8.1.2 Capital Costs

Table 8.1-6 shows the bases and methodology for developing capital cost estimates for uncontrolled boilers and control methods. Specific equipment lists and assumptions regarding the capital cost bases for individual types of boilers and control systems are detailed in the appropriate Individual Technology Assessment Reports (ITARs) and the references listed in Table 8.1-4. Boiler capital costs are for new individual boilers of the specified design capacity. Savings associated with multiple boiler units or adding a boiler to an existing powerhouse are not considered. Retrofit control costs are addressed separately in Section 8.2.3.

8.1.3 Operating and Maintenance Costs

Table 8.1-7 lists the components of boiler and control method operating and maintenance (O&M) costs. Specific assumptions with regard to O&M cost bases for individual types of boilers and control methods are detailed in the appropriate ITARs.

TABLE 8.1-4. SUMMARY OF SOURCES OF COSTING INFORMATION

Costed Item	Type of Information	Developing Organization	Date(s)	Reference
All boilers and control systems	General summary of cost development and results	Radian	4/82	2
Uncontrolled boilers	Algebraic cost algorithms	PEDCo	1/80, 6/79	3,4
FGD systems	Algebraic cost algorithms	Acurex	12/79	5
FGD systems	Technology Assessment Report giving individual system costs	Radian	11/79	6
FGD systems	Revisions to cost algorithms developed by Acurex	Radian	2/80, 6/80	7,8
SM, SSS's	Technical memo developing cost algorithms from vendor quotes	Radian	1/81	9
ESP, FF's	Algebraic cost algorithms	PEDCo	4/80	10
NO_x controls	Technology Assessment Report giving individual system costs	Acurex	12/79	11
HDS oils	Technology Assessment Report on oil cleaning estimating costs of HDS oil	Catalytic	1979	15
HDS oils	Issue paper on oil cleaning	Radian	11/80	16
Compliance coals	Technical memo estimating costs of coal with reduced sulfur content	Radian	2/80	17

TABLE 8.1-5. EMISSION CONTROL SYSTEM GENERAL DESIGN SPECIFICATIONS[a]

Control Device	Item	Specification
Single Mechanical Collectors	Material of construction	Carbon steel
	Pressure drop[b]	1.0 kPa (4 in. H_2O gauge)
Side Stream Separators	Material of construction	Mechanical collector and fabric filter: carbon steel
	Pressure drop[b]	1.5 kPa (6 in. H_2O gauge)
	Amount of gas flow treated in fabric filter	20%
	Fabric filter	Multi-compartment pulse-jet with Teflon coated glass felt bags
	Bag life	2 years
Electrostatic Precipitators (ESP)	Material of construction	Carbon steel (insulated)
	Specific collection areas[c] (plate area per gas volume for 21.5 ng/J (0.05 lb/10^6Btu) control levels	Underfeed and chaingrate Stokers: 33.2 $m^2/m^3/s$ (169 $ft^2/10^3acfm$) Spreader Stokers: 46.4 $m^2/m^3/s$ (236 $ft^2/10^3acfm$) Pulverized Coal: 50.0 $m^2/m^3/s$ (254 $ft^2/10^3acfm$) Oil-Fired: 78.7 $m^2/m^3/s$ (400 $ft^2/10^3acfm$)
	Pressure drop[b]	0.25 kPa (1 in. H_2O gauge)
	Power demand	32 W/m^2 (3 W/ft^2)

TABLE 8.1-5. (CONTINUED)

Control Device	Item	Specification
Fabric Filter	Material of construction	Carbon steel (insulated)
	Cleaning method	Reverse-air (multi-compartment)
	Air to cloth ratio	1 cm/s (2 ft/min)
	Bag material	Teflon-coated fiberglass
	Bag life	2 years
	Pressure drop[b]	1.5 kPa (6 in. H_2O gauge)
Double Alkali FGD (SO_2 removal only)	Scrubber type	Tray tower
	Pressure drop[b]	1.5 kPa (6 in. H_2O gauge)
	Scrubber sludge	60% solids
	Sludge disposal	Trucked to off-site landfill
Sodium Throwaway FGD (either SO_2 removal only or combined SO_2 & PM removal)	Material of construction	316 stainless steel
	Scrubber type	Variable throat venturi
	Pressure drop[b]	2.0 kPa (8 in. H_2O)
	Waste water treatment	Treated in existed facility
Double Alkali FGD (SO_2 and PM removal)	Material of construction	316 stainless steel
	Scrubber type	Variable throat venturi
	System design	Includes 80% efficient single mechanical collector upstream of scrubber
	Pressure drop[b] (over SM and scrubber)	5.0 kPa (20 in. H_2O gauge)
	Sludge disposal	Dry particulate collected in single mechanical combined with 60% solids scrubber sludge and trucked to off-site landfill

TABLE 8.1-5. (CONTINUED)

Control Device	Item	Specification
Dry Scrubbing (spray drying, SO_2 and PM removal)	Materials of construction	Carbon steel spray dryer and fabric filter (insulated)
	Reagent	Lime; no solids recycle
	Fabric filter	Reverse-air (same design as previous fabric filter
	Pressure drop[b]	1.5 kPa (6 in. H_2O gauge)
	Solids disposal	Trucked to off-site landfill

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[a] For more detail on system design and operating parameters see Individual Technology Assessment Reports (ITARS).

[b] All pressure drops refer to gas side pressure drop across entire control system.

[c] Values shown are for sulfur content of 3.5% in coal feed to boiler. Boilers firing coals with lower sulfur content have somewhat higher SCA values.

TABLE 8.1-6. CAPITAL COST COMPONENTS[a]

(1) Direct Costs

Equipment
Installation

Total Direct Costs

(2) Indirect Costs[12]

Engineering	(10% of direct costs for boiler, NO_x, and PM controls; For boilers with heat inputs $\leq$58.6 MW, FGD system engineering costs are taken as 10% of direct costs for an FGD system at 90% removal on 58.6 MW unit. For 117.2 MW boilers, engineering costs for SO_2 controls are 10% of direct costs)
Construction and Field Expenses	(10% of direct costs)
Construction Fees	(10% of direct costs)
Start Up Costs	(2% of direct costs)
Performance Costs	(\$2000 for NO_x systems, 1% of direct costs for boilers, FGD systems, and PM systems)

Total Indirect Costs

(3) Contingencies[12] = 20% of (Total indirect + Total Direct Costs)

(4) Total Turnkey Cost = Total Indirect Cost + Total Direct Cost + Contingencies

(5) Working Capital[12] = 25% of Total Direct Operating Costs (See Table 8.1-7)

(6) Total Capital Cost = Total Turnkey + Working Capital

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[a] Boiler and each control system costed separately; factors apply to cost of boiler or control system considered; i.e., the engineering cost for the PM control system is 10% of the direct cost of the PM control system.

TABLE 8.1-7 OPERATING AND MAINTENANCE COST COMPONENTS

(1) Direct Operating Costs[a]

- Direct Labor
- Supervision
- Maintenance Labor, Replacement Parts and Supplies
- Electricity
- Water
- Steam
- Waste Disposal
  - Solids (Fly ash and bottom ash)
  - Sludge
  - Liquid
- Chemicals

- Total Non-Fuel O & M
- Fuel

- Total Direct Operating Costs

(3) Indirect Operating Costs (Overhead)[b,c]

- Payroll (30% Direct Labor)
- Plant (26% of Direct labor + Supervision + Maintenance costs)

(3) Total Annual Operating and Maintenance Costs =
Total Direct + Total Indirect Costs

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[a] For HDS and CC the total direct operating cost (DOC) is taken as:

$$DOC = \left(\frac{\text{fuel use}}{\text{hour}}\right)\left(\frac{8760\ \text{hr}}{\text{yr}}\right)\left(\begin{matrix}\text{boiler load}\\ \text{factor}\end{matrix}\right)\left(\begin{matrix}\text{incremental cost}\\ \text{of fuel}\end{matrix}\right)$$

where incremental cost of fuel is the cost of CC or HDS fuel minus the cost of the fuel used in the uncontrolled boiler.

[b] Boilers and each control systems are costed separately; factors apply to boiler or control system being considered, (i.e., payroll overhead for FGD system is 30% direct labor requirement of FGD system).

[c] Factors recommended in Reference 12, p. 117.

In addition to their dependence on boiler size, fuel type, and the flow rate and composition of the flue gas to be treated, the O&M costs for the boiler and control methods are a function of capacity utilization (load factor), utility unit costs (steam, electricity, water), and unit costs for raw materials, waste disposal, and labor. Table 8.1-8 lists the values selected for these parameters in this analysis. Fuel costs are a major component of boiler operating costs. The prices used for boiler fuels are presented in Table 8.1-9. As the table indicates, 1990 fuel prices (in 1978 dollars) are used in the cost analysis to account for the expected escalation of fuel prices above the general inflation rate during the period in which a regulation would be effective. The costs of uncleaned oils, natural gas, HSC, and LSC are based on fuel prices developed for the IFCAM model.[13,14] The prices for the HDS cleaned oils are based on oil cleaning costs developed in an ITAR[15] and updated by Radian to 1990 fuel prices in a subsequent memo.[16] The prices for the intermediate sulfur coals (compliance coals) use estimates of the cost premium associated with obtaining coals with lower sulfur content compared to high sulfur coal.[17]

Combustion modification techniques used to control NO_x emissions can affect the magnitude of the fuel cost component. Operation with low excess air (LEA) to control NO_x tends to increase boiler thermal efficiency, resulting in fuel savings and a reduction in the fuel cost component. The use of staged combustion air (SCA) to control NO_x emissions (low excess air in combination with overfire air) can result in increased fuel use, and therefore increased fuel costs. Reduced air preheat (RAP) control techniques may reduce boiler efficiency, increasing fuel use. The incremental increase or decrease in fuel costs associated with combustion modifications is reported as an operating cost for NO_x control in subsequent sections.

Likewise, use of more expensive intermediate sulfur coals (compliance coals) or HDS cleaned oils for SO_2 and/or PM control results in increased fuel costs compared to the use of HSC or uncleaned oils. These incremental fuel costs are reported as an operating cost for SO_2 and/or PM control in subsequent sections.

TABLE 8.1-8. LOAD FACTORS AND UTILITY AND UNIT OPERATING COSTS[a]

(1) Load Factors (Capacity Utilization)[12]

Boiler Capacity and Fuel	Load Factor
8.8 MW (30 x 10^6 Btu) Natural Gas & Distillate Oil	0.45
44 MW (150 x 10^6 Btu) Natural Gas & Distillate Oil	0.55
All residual-fired boilers	0.55
All coal-fired boilers	0.60

(2) Utility Costs[12]

Electricity	\$0.0258/kwh
Water	\$0.04/m^3 (\$0.15/10^3 gal)
Steam	\$3.01/GJ (\$3.5/10^3 lb)

(3) Raw Material, Labor and Waste Disposal Costs[12]

Waste Disposal[3,6]

Solids (Ash)	\$0.0166/kg (\$15/ton)	trucked to landfill
Sludge	\$0.0166/kg (\$15/ton)	
Liquid	\$0.47/m^3 (\$1.79/10^3 gal)	

Chemicals

Na_2CO_3	\$0.099/kg	(\$90/ton)
Lime	\$0.039/kg	(\$35/ton)
Limestone	\$0.00883/kg	(\$8/ton)

Labor

Direct labor	\$12.02/man-hour
Supervision labor	\$15.63/man-hour
Maintenance labor	\$14.63/man-hour

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[a] June 1978 dollars

TABLE 8.1-9. FUEL PRICES (June 1978 $)[13,14,15,16,17]

Fuel	Price[a] $/GJ ($/10^6 Btu)
Natural Gas	\$5.12 (\$4.85)
Distillate Oil (0.5% S)	\$6.39 (\$6.06)
Distillate Oil (0.3% S W/HDS)	\$6.83 (\$6.47)
Residual Oil (3.0% S)	\$5.12 (\$4.85)
Residual Oil (1.6% S W/HDS)	\$5.58 (\$5.29)
Residual Oil (0.8% S W/HDS)	\$5.87 (\$5.56)
Residual Oil (0.3% S W/HDS)	\$6.15 (\$5.83)
Low Sulfur Coal (0.6% S)	\$2.54 (\$2.41)
High Sulfur Coal (3.5% S)	\$1.91 (\$1.81)
Intermediate Sulfur Coal (1.6% S)[b]	\$2.35 (\$2.23)
Intermediate Sulfur Coal (1.2% S)[c]	\$2.43 (\$2.30)

[a] Price is projected 1990 price in 1978 $ and includes transportation costs to Midwest boiler location.

[b] Used to achieve 1076 ng/J (2.5 lb/10^6 Btu) emission limit.

[c] Used to achieve 860 ng/J (2.0 lb/10^6 Btu) emission limit.

8.1.4 Annualized Costs

The total annualized costs ($ per year) for uncontrolled boilers, each control system, and the total annualized cost of boilers and controls are calculated for each model boiler based on the boiler capacity utilization. As depicted in Table 8.1-10, the total annualized cost is the sum of the annual O&M costs and annualized capital charges.

The capital recovery factors used in this study are based on equipment lives specified in the ITARs and an interest rate of 10 percent. The 10 percent interest rate should not be considered as the actual cost of borrowing capital since this analysis is not intended as an economic feasibility study. Rather, 10 percent was selected as a typical nominal rate of return on investment to provide a basis for calculation of capital recovery charges. The capital recovery factors used for the boiler and control equipment investments are presented in Table 8.1-10.

8.2 ANALYSIS OF COST IMPACTS

This subsection presents the results of the model boiler cost impact analysis. This analysis focuses on the incremental cost impacts in going from the baseline control alternative to more stringent alternatives. Capital costs, annualized costs, and cost effectiveness of emission control methods are discussed in the following subsections. In addition, a brief discussion of cost impacts for retrofit installations is also included since certain modified or reconstructed boilers may become subject to Federal regulations as discussed in Chapter 5.

8.2.1 Capital Costs

The capital costs for each model boiler are presented in Tables 8.2-1 through 8.2-3. Individual costs for each uncontrolled boiler, each control system, and the total model boiler costs are given. Also included is the "normalized" total capital cost calculated by dividing the total cost of the model boiler by the boiler capacity. Normalized capital costs provide a measure of the capital investment required per unit of installed boiler capacity.

TABLE 8.1-10. ANNUALIZED COST COMPONENTS

1. Total Annualized Cost = Annual Operating Costs + Capital Charges

2. Capital Charges

   = Capital recovery + interest on working capital + miscellaneous (G&A, taxes and insurance)

3. Calculation of Capital-Related Cost Components

   A. Capital Recovery = Capital Recovery Factor (CRF) x Total Turnkey Cost

System	Number of years of Useful Life = n	CRF = $\frac{i\,(1+i)^n}{(1+i)^n-1}$ with i = 10%
Boiler	30	0.1061
PM	20	0.1175
FGD	15	0.1315
NO_x	30	0.1061

   B. Interest on Working Capital = 10% of working capital

   C. G&A, taxes and insurance = 4% of total turnkey cost

TABLE 8.2-1. CAPITAL COSTS OF HSC MODEL BOILERS[2]
(JUNE 1978$)

		Capital Costs ($1000)						Percent Increase in Costs	
Control Alternative	Model Boiler	Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized[c] Total	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	HSC-30-Unc, CC, SM	1922	0	16.6	62.6	2002	66.7	4.2	0
1	HSC-30-Unc, CC, SSS	1922	0	19.3	111	2053	68.4	6.8	2.5
2	HSC-30-Unc, CC, ESP	1922	0	19.3	362	2304	76.8	19.9	15.1
3	a								
4	HSC-30-FGD, FGD/PM	1922	0	981	w/SO_2	2903	96.8	51.0	45.0
5	HSC-30-FGD, ESP	1922	0	841	289	3052	101.7	58.8	52.4
B	HSC-75-Unc, CC, SM	3533	0	41.4	125	3700	49.3	4.7	0
1	HSC-75-Unc, CC, SSS	3533	0	48.3	229	3810	50.8	7.8	3.0
2	HSC-75-Unc, CC, ESP	3533	0	48.3	693	4275	57.0	21.0	15.5
3	a								
4	HSC-75-Unc, FGD, FGD/PM	3533	0	1355	w/SO_2	4888	65.2	38.4	32.1
5	HSC-75-Unc, FGD, ESP	3533	0	1223	546	5303	70.7	50.1	43.3
B	HSC-150-Unc, CC, SM	8015	0	82.7	217	8314	55.4	3.7	0
1	HSC-150-SCA, CC, SSS	8015	22.0	96.6	400	8533	56.9	6.5	2.6
2	HSC-150-SCA, CC, ESP	8015	22.0	96.6	1475	9608	64.1	19.9	15.6
3	a								
4	HSC-150-SCA, FGD, FGD/PM	8015	22.0	1842	w/SO_2	9878	65.9	23.2	18.8
5	HSC-150-SCA, FGD, ESP	8015	22.0	1657	1369	11063	73.8	38.0	33.1
B	HSC-400-LEA, FGD[b], FGD/PM	19059	44.0	2756	w/SO_2	21859	54.6	14.7	0
1	a								
2	HSC-400-SCA, FGD, FGD/PM	19059	87.0	2816	w/SO_2	21962	54.9	15.2	0.5
3	HSC-400-SCA, FGD, ESP	19059	87.0	2576	1848	23569	58.9	23.7	7.8

[a] Alternative requiring 50% SO_2 removal not applicable to HSC boilers since resulting emissions would not meet baseline requirements.

[b] Baseline requires 78.9% SO_2 removal; other alternatives require 90% removal.

[c] Normalized total is capital cost divided by boiler capacity ($1000/$10^6$Btu/hr).

TABLE 8.2-2. CAPITAL COSTS OF LSC MODEL BOILERS[2]
(JUNE 1978$)

		Capital Costs ($1000)						Percent Increase in Costs	
Control Alternative	Model Boiler	Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized[a] Total	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	LSC-30-Unc, Unc, SM	2326	0	0	63.6	2390	79.7	2.8	0
1	LSC-30-Unc, Unc, SSS	2326	0	0	113	2440	81.3	4.9	2.1
2	LSC-30-Unc, Unc, FF	2326	0	0	269	2595	86.5	11.6	8.6
3	LSC-30-Unc, DS, DS/PM	2326	0	653	W/SO_2	2979	99.3	28.1	24.6
4	LSC-30-Unc, FGD, FGD/PM	2326	0	768	W/SO_2	3094	103.1	33.0	29.5
5	LSC-30-Unc, FGD, FF	2326	0	604	269	3199	106.6	37.5	33.8
B	LSC-75-Unc, Unc, SM	4274	0	0	127	4401	58.7	3.0	0
1	LSC-75-Unc, Unc, SSS	4274	0	0	233	4507	60.1	5.5	2.4
2	LSC-75-Unc, Unc, FF	4274	0	0	667	4941	65.9	15.6	12.3
3	LSC-75-Unc, DS, DS/PM	4274	0	1108	W/SO_2	5382	71.8	25.9	22.3
4	LSC-75-Unc, FGD, FGD/PM	4274	0	1067	W/SO_2	5340	71.2	24.9	21.3
5	LSC-75-Unc, FGD, FF	4274	0	877	667	5817	77.6	36.1	32.2
B	LSC-150-Unc, Unc, SM	8690	0	0	218	8908	59.4	2.5	0
1	LSC-150-SCA, Unc, SSS	8690	22.0	0	405	9118	60.8	4.9	2.4
2	LSC-150-SCA, Unc, FF	8690	22.0	0	1142	9854	65.7	13.4	10.6
3	LSC-150-SCA, DS, DS/PM	8690	22.0	1748	W/SO_2	10461	69.7	20.4	17.4
4	LSC-150-SCA, FGD, FGD/PM	8690	22.0	1488	W/SO_2	10200	68.0	17.4	14.5
5	LSC-150-SCA, FGD, FF	8690	22.0	1191	1142	11045	73.6	27.1	24.0
B	LSC-400-LEA, Unc, FF	19924	44.0	0	2147	22116	55.3	11.0	0
1	LSC-400-SCA, DS, DS/PM	19924	87.0	3341	W/SO_2	23353	58.4	17.2	5.6
2	LSC-400-SCA, FGD, FGD/PM	19924	87.0	2285	W/SO_2	22182	55.5	11.3	0.3
3	LSC-400-SCA, FGD, FF	19924	87.0	1850	2147	24009	60.0	20.5	8.6

[a] Normalized total is total capital cost divided by boiler capacity ($1000/$10^6$ Btu/hr).

TABLE 8.2-3. CAPITAL COSTS OF OIL- AND GAS-FIRED MODEL BOILERS[2] (JUNE 1978 $)

Control Alternative	Model Boiler	Capital Costs ($1000)						Percent Increase in Costs	
		Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized Total[a]	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	RES-30-Unc, HDS(1.6), Unc	707	0	15.9	0	723	24.1	2.3	0
1	RES-30-LEA, HDS(0.8), HDS/PM	707	12.0	25.6	W/SO_2	745	24.8	5.4	3.0
2	RES-30-LEA, HDS(0.3), HDS/PM	707	12.0	35.4	W/SO_2	754	25.1	6.6	4.3
3	RES-30-LEA, FGD/Na, FGD/PM	707	12.0	391	W/SO_2	1110	37.0	57.0	53.5
4	RES-30-LEA, FGD/Na, ESP	707	12.0	391	401	1511	50.4	113.7	109.0
B	RES-150-Unc, HDS(1.6), Unc	2735	0	79.5	0	2815	18.8	2.9	0
1	RES-150-LEA, HDS(0.8), HDS/PM	2735	17.0	128	W/SO_2	2864	19.2	5.3	2.3
2	RES-150-LEA, HDS(0.3), HDS/PM	2735	17.0	193	W/SO_2	2912	19.5	7.1	4.0
3	RES-150-LEA, FGD, FGD/PM	2735	17.0	1475	W/SO_2	4210	28.2	54.6	50.2
4	RES-150-LEA, FGD, ESP	2735	17.0	1338	1057	5130	34.3	88.2	82.8
B	RES-400-LEA, FGD[b], FGD/PM	14039	27.4	2246	W/SO_2	16285	40.8	16.2	0
1	RES-400-LEA, FGD, FGD/PM	14039	27.4	2313	W/SO_2	16352	40.9	16.7	0.4
2	RES-400-LEA, FGD, ESP	14039	27.4	2125	1692	17856	44.7	27.4	9.6
B	DIS-30-Unc, Unc, Unc	871	0	0	0	871	29.0	0	0
1	DIS-30-LEA, HDS(0.3), Unc	871	14.0	12.1	0	897	29.9	3.0	3.0
B	DIS-150-Unc, Unc, Unc	2927	0	0	0	2927	19.5	0	0
1	DIS-150-LEA/RAP, HDS(0.3), Unc	2927	19.7	74.1	0	3021	20.1	3.2	3.2
B	NG-30-Unc, Unc, Unc	835	0	0	0	835	27.8	0	0
1	NG-30-LEA, Unc, Unc	835	14.0	0	0	849	28.3	1.7	1.7
B	NG-150-Unc, Unc, Unc	2709	0	0	0	2709	18.1	0	0
1	NG-150-LEA/RAP, Unc, Unc	2709	20.9	0	0	2730	18.2	0.8	0.8

[a] Normalized total is total capital cost divided by boiler capacity ($1000/$10^6$ Btu/hr).

[b] 75% SO_2 removal efficiency required at baseline control alternative.

The last two columns in Table 8.2-1 thru 8.2-3 present percent increases in the total model boiler capital cost. These percent increases are calculated with respect to:

- Uncontrolled boiler capital cost, and
- Baseline controlled boiler capital cost (cost of boiler and control method required under the baseline control alternative).

For those cases where a control device is used, the percent increase in costs over the uncontrolled case provides a measure of the additional capital required to construct the control device(s). The percent increase over the baseline case provides a measure of the additional capital required to meet emission limits more stringent than the emission limits based on existing regulations (baseline). In the discussions of capital costs, the major emphasis will be the comparison of percent increases in capital cost over baseline for various control alternatives.

It should be noted that non-capital intensive control methods, such as compliance coal and HDS cleaned oils, do require working capital in order to purchase more expensive fuels. Working capital costs are reported as capital costs in Tables 8.2-1 through 8.2-3. Also, many model boilers use control methods which simultaneously control both SO_2 and PM emissions. In Tables 8.2-1 thru 8.2-3, the total control system cost is reported as an SO_2 control cost with an appropriate note in the PM control cost column.

8.2.1.1 Small Coal-Fired Model Boilers. This subsection discusses the capital costs of controls for coal-fired boilers with thermal input capacities of 73 MW (250 x 10^6 Btu/hr) and less. The total normalized capital costs for each HSC and LSC model boiler in Tables 8.2-1 and 8.2-2 are graphically represented in Figures 8.2-1 and 8.2-2. The small insert table in each figure provides a key to the SO_2 and PM control technologies used by each model boiler in achieving the emission limits in the control alternatives. NO_x controls are not included in the insert tables. In general, NO_x capital costs are very small and do not have a significant impact on overall capital costs. Capital costs for NO_x control by

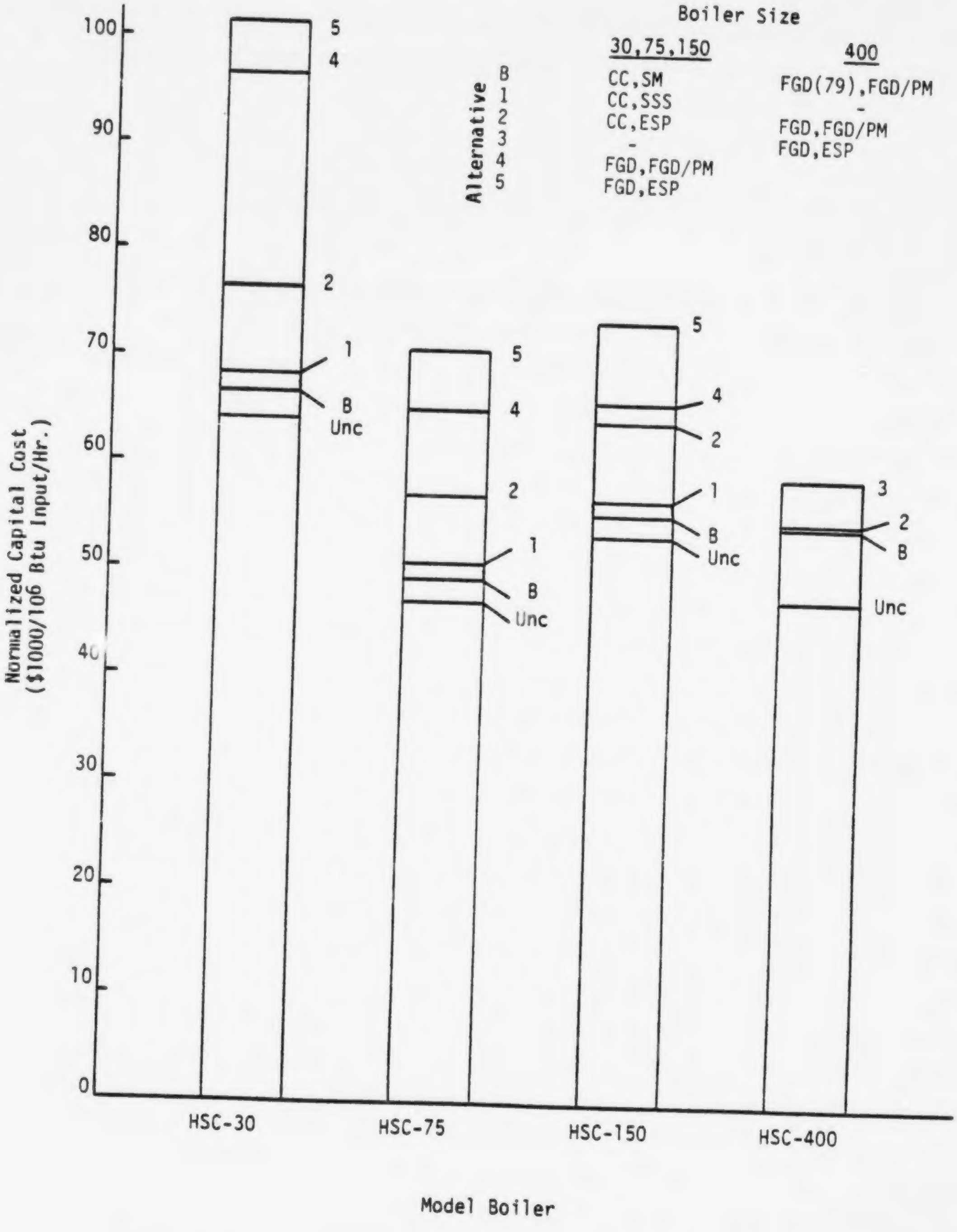

Figure 8.2-1. Capital costs of control alternatives applied to HSC-fired model boilers.

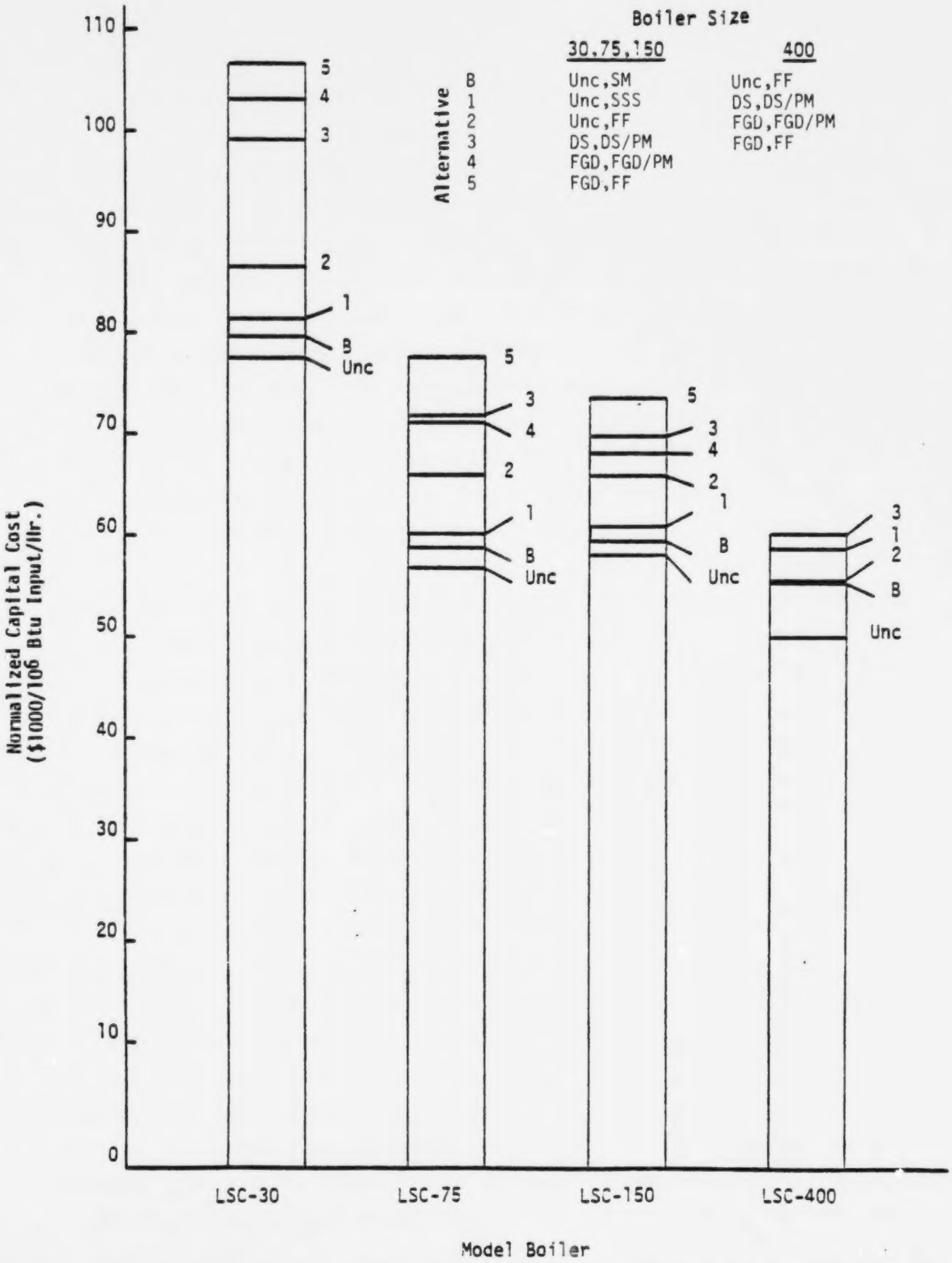

Figure 8.2-2. Capital costs of control alternatives applied to LSC-fired model boilers.

combustion modification result in less than a 0.3 percent increase over baseline costs for all coal-fired model boilers.

Single mechanical collectors and sidestream separators are the least expensive PM control methods for coal-fired boilers smaller than 73 MW (250 x 10^6 Btu/hr). Compared to the baseline alternative (which uses a single mechanical collector), capital cost increases of 3 percent and less are incurred in using the sidestream separator (Alternative 1) control. A relatively larger capital cost increase is incurred when an ESP or fabric filter is required as is the case with Alternative 2. For HSC model boilers smaller than 73 MW, which require an ESP to meet the emission limits in Alternative 2, cost increases over baseline are approximately 15 to 16 percent. Fabric filters used on LSC model boilers under Alternative 2 result in increases of 8 to 12 percent over the size range of 8.8 MW (30 x 10^6 Btu/hr) to 44 MW (150 x 10^6 Btu/hr).

An apparent diseconomy of scale for the HSC-150 model boiler ESP can be noted when compared to the ESP's used on the smaller boilers. The relatively high cost for the larger ESP is explained by two factors: (1) the uncontrolled particulate matter emission rate of the larger spreader stoker is considerably higher than the smaller underfeed and chaingrate stokers at 2500 ng/J (5.82 lb/10^6 Btu) vs. 955 ng/J (2.22 lb/10^6 Btu), and (2) ESP costs are very sensitive to collection efficiency requirements. Since the ESP for the spreader stoker requires a larger collection area relative to the flue gas flow, the end result is a more expensive ESP on a normalized cost basis. Unlike ESP's, fabric filters are not sensitive to collection efficiency and thus do not exhibit this anomaly.

The largest capital costs are associated with the control alternatives which require FGD systems. Capital costs for SO_2 control via compliance coal on HSC model boilers are relatively small since working capital for the higher priced fuel is the only capital cost. For the HSC model boilers the increases in capital costs over baseline associated with the use of compliance coal are less than one percent of the model boiler cost. Capital costs jump sharply under Alternatives 4 and 5 which require 90 percent SO_2

removal with double alkali FGD. Alternative 4 requires a combined SO_2 and PM scrubbing system in which PM is removed in the double alkali scrubber. Capital costs for this system vary from a 19 percent to 45 percent increase over baseline, with the largest percent increase associated with the 8.8 MW (30×10^6 Btu/hr) boiler. Alternative 5 requires an ESP for PM removal in addition to the FGD system required for SO_2 removal. The separate SO_2 and PM systems required under Alternative 5 are the most expensive alternatives evaluated. Cost increases range from 33 percent to 52 percent over baseline for the boiler sizes examined, with the percent increasing as boiler size decreases.

The costs of FGD systems applied to boilers firing LSC are similar to costs for boilers firing HSC. The capital costs of the dry scrubbing system used in Alternative 3 are similar to the costs of the combined double alkali SO_2 and PM control systems despite the higher SO_2 removal of the double alkali system (90 percent vs. 50 percent). In fact, the dry scrubbing system is more expensive than the double alkali system on all but the smallest LSC model boiler. This result is attributable to the capital cost of the fabric filter which is included with the dry scrubbing system. The fabric filter collects waste solids generated in the spray dryer and fly ash. As with the HSC model boilers, the maximum capital cost impacts are incurred with use of separate SO_2 and PM control systems under Alternative 5. These capital cost increases over baseline range from 21 percent to 32 percent depending on boiler size with the percentage increasing with decreasing boiler size.

All the FGD systems show strong economies of scale. The combined SO_2 and PM control system used on the HSC-150 model boiler costs only 35 percent more than the same system applied to the HSC-75 model boiler, yet treats over twice the gas flow and removes over five times as much PM. The economies of scale of FGD systems result in a narrowing of the cost difference between Alternatives 2 and 4 as boiler size increases. For the small HSC-30 unit, use of a combined SO_2 and PM scrubber (Alternative 4) results in a capital cost increase of 26 percent compared to use of compliance coal and an ESP (Alternative 2). At the HSC-150 size, however, the same comparison reveals only a three percent increase in costs. At the larger size, most of the FGD cost is recouped by elimination of the relatively expensive ESP since the combined system relies on the FGD scrubber for PM removal.

8.2.1.2 Large Coal-Fired Model Boilers. Boilers larger than 73 MW (250 x 10^6 Btu/hr) are subject to the existing NSPS, resulting in more stringent baseline control requirements for the HSC-400 and LSC-400 model boilers compared to the smaller coal-fired boilers. Thus, the alternatives examined for the large coal-fired boilers show much smaller percent increases in cost over baseline since the baseline alternatives already require considerable costs for emission control.

For the HSC-400 model boiler, the baseline SO_2 emission limit of 516 ng/J (1.2 lb/10^6 Btu) requires an SO_2 removal efficiency of 79 percent. Increasing this removal efficiency to 90 percent, as required under Alternative 2, results in a 0.5 percent increase in capital costs. Both the baseline and Alternative 2 model boilers use combined SO_2 and PM scrubbing with double alkali systems. The most stringent alternative, Alternative 3, requires a separate PM control system (ESP) in addition to a FGD system. Alternative 3 results in a 7.8 percent increase in capital costs over baseline for the HSC-400 boiler.

For the LSC-400 model boiler, an additional alternative requiring 50 percent SO_2 removal via dry scrubbing was examined. As was the case for the LSC-150 model boiler, capital costs for dry scrubbing at this removal are greater than the cost of a double alkali combined SO_2 and PM control system at 90 percent SO_2 removal. The most expensive system is a separate SO_2 and PM control scheme with double alkali scrubbing for SO_2 and a fabric filter for PM. This system results in an 8.6 percent increase in costs over baseline. The higher percent increases over baseline for LSC compared to HSC for equivalent emission reduction requirements are due to the different systems used at baseline: HSC boilers require FGD systems at the baseline level; LSC boilers do not. Thus, the alternatives beyond baseline for LSC boilers require the addition of an FGD system resulting in greater capital cost increases over baseline.

8.2.1.3 Oil- and Gas-Fired Model Boilers. The capital costs for residual oil-fired model boilers, presented earlier in Table 8.2-3, are graphically illustrated in Figure 8.2-3. NO_x controls are not specified in the insert table. As is the case for coal-fired boilers, capital costs for NO_x control on residual-fired boilers are generally small. In all cases, NO_x capital costs are less than 1.5 percent of the total model boiler cost.

The sharp increase in capital costs associated with the use of FGD systems is also evident for residual oil-fired boilers. For boilers smaller than 73 MW (250 x 10^6 Btu/hr) increases in capital costs over baseline for model boilers firing HDS oils for SO_2 control (Alternatives 1 and 2) range from 3 percent to 4 percent for the range of boiler sizes examined. This cost increase is primarily due to increased working capital costs associated with the purchase of HDS cleaned oils. Application of FGD systems to the same size residual oil-fired boilers results in substantially greater capital cost increases relative to capital costs of HDS oil use.

Combined SO_2 and PM systems (Alternative 3) result in capital cost increases of 50 to 54 percent for boilers smaller than 73 MW. The RES-30 model boiler uses a sodium throwaway FGD system while the RES-150 uses a double alkali system. The separate SO_2 and PM control systems using FGD scrubbers and ESP's are the most capital intensive control systems evaluated. Increases in capital cost over baseline are 109 percent and 83 percent for the RES-30 and RES-150 model boilers, respectively.

For the large residual oil-fired model boiler (RES-400) a combined SO_2 and PM scrubbing system is required to meet the baseline SO_2 emission limit of 344 ng/J (0.8 lb/10^6 Btu). To meet this limit, an SO_2 removal efficiency of 75 percent is required. Increasing the removal efficiency to 90 percent, as required under Alternative 1, results in a 0.4 percent increase in capital costs. Under Alternative 2, an ESP is required for PM control in addition to the FGD system. Alternative 2 results in a capital cost increase over baseline of 9.6 percent.

An apparent diseconomy of scale can be noted when comparing the normalized capital costs of the uncontrolled RES-150 and RES-400 model boilers. This result is due to the different types of boilers used. The

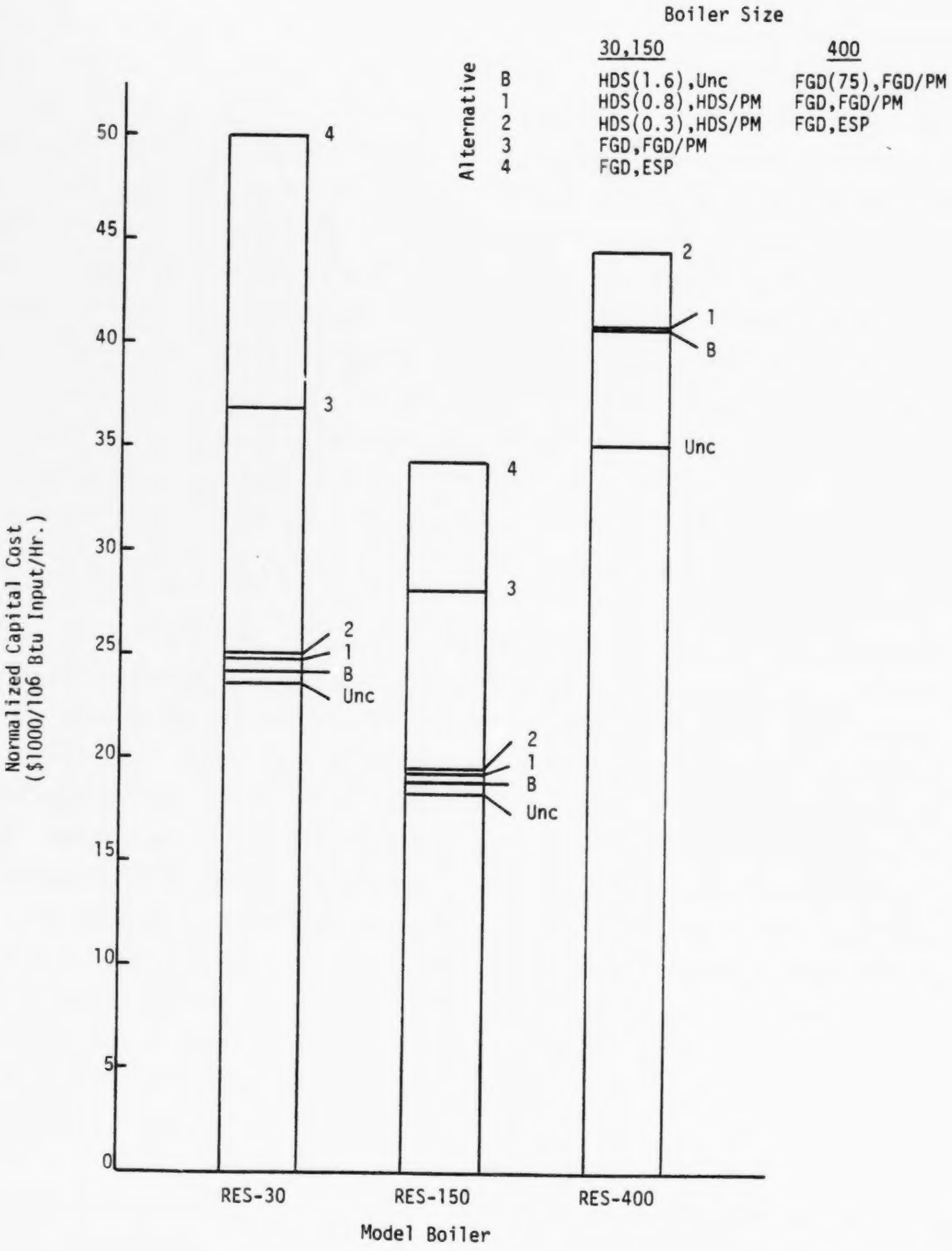

Figure 8.2-3. Capital costs of control alternatives applied to residual oil-fired model boilers. (June 1978 $)

smaller boiler is a package unit while the larger boiler is a field-erected unit. Since field erected units are more expensive than shop erected units, the net result is a relatively expensive RES-400 boiler.

For the distillate oil-fired model boilers, cost increases of 3.0 to 3.2 percent are incurred in going from baseline to Alternative 1. These capital costs are for the LEA and/or RAP systems used for NO_x control, and incremental working capital for purchase of HDS cleaned oils. For natural gas-fired boilers, only NO_x controls are used in Alternative 1. The cost increases over baseline of the LEA and/or RAP systems used are 1.7 percent and 0.8 percent for the NG-30 and NG-150 model boilers, respectively.

8.2.2 Annualized Costs

Model boiler annualized costs are presented in Tables 8.2-4 through 8.2-6. The total model boiler annual costs have been normalized by dividing by the total annual heat input to the boiler. The resulting numbers provide a measure of the total cost of firing a unit of fuel for a given model boiler. Percent increases in annualized costs for each model boiler over the uncontrolled case and the baseline case are also provided. In the discussions of annualized costs, the major emphasis will be the comparison of percent increases in capital cost over baseline for various control alternatives.

As indicated earlier in Table 8.1-10, annualized costs are the sum of capital charges, operating costs, and maintenance costs. Included in the boiler operation costs are fuel costs. The annualized costs provide a measure of the total annual cost to build, operate, and maintain a boiler and control system.

Annualized costs of the boiler and emission controls are a function of boiler capacity factor. All costs are presented on the basis of the capacity factors specified in Table 8.1-8. An analysis of control costs for boilers with lower capacity factors is contained in a separate report.[2]

8.2.2.1 Small Coal-Fired Model Boilers. This subsection discusses the annualized costs for coal-fired boilers with thermal input capacities of 73 MW (250×10^6 Btu/hr) and less. The total normalized annual costs for each HSC and LSC model boiler are graphically represented in Figures 8.2-4

TABLE 8.2-4. ANNUALIZED COSTS OF HSC MODEL BOILERS[2]
(JUNE 1978$)

Control Alternative	Model Boiler	Annualized Costs ($1000/yr)[c]						Percent Increase in Costs	
		Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized[d] Total	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	HSC-30-Unc, CC, SM	1027	0	67.9	14.6	1110	7.04	8.1	0
1	HSC-30-Unc, CC, SSS	1027	0	79.2	30.5	1137	7.21	10.7	2.4
2	HSC-30-Unc, CC, ESP	1027	0	79.2	92.4	1199	7.60	16.7	8.0
3	a								
4	HSC-30-FGD, FGD/PM	1027	0	458	w/SO_2	1485	9.42	44.6	33.8
5	HSC-30-FGD, ESP	1027	0	419	80.0	1527	9.68	48.7	37.6
B	HSC-75-Unc, CC, SM	2076	0	169	31.1	2276	5.77	9.6	0
1	HSC-75-Unc, CC, SSS	2076	0	197	60.0	2334	5.92	12.4	2.5
2	HSC-75-Unc, CC, ESP	2076	0	197	158	2432	6.17	17.1	6.9
3	a								
4	HSC-75-Unc, FGD, FGD/PM	2076	0	616	w/SO_2	2692	6.83	29.7	18.3
5	HSC-75-Unc, FGD, ESP	2076	0	572	133	2781	7.05	34.0	22.2
B	HSC-150-Unc, CC, SM	3575	0	339	77.8	3992	5.06	11.7	0
1	HSC-150-SCA, CC, SSS	3575	5.4	396	126	4103	5.20	14.8	2.8
2	HSC-150-SCA, CC, ESP	3575	5.4	396	331	4307	5.46	20.5	7.9
3	a								
4	HSC-150-SCA, FGD, FGD/PM	3575	5.4	873	w/SO_2	4453	5.65	24.6	11.5
5	HSC-150-SCA, FGD, ESP	3575	5.4	778	311	4669	5.92	30.6	17.0
B	HSC-400-LEA, FGD[b], FGD/PM	8817	-8.4	1461	w/SO_2	10270	4.88	16.5	0
1	a								
2	HSC-400-SCA, FGD, FGD/PM	8817	53.9	1540	w/SO_2	10411	4.95	18.1	1.4
3	HSC-400-SCA, FGD, ESP	8817	53.9	1328	524	10722	5.10	21.6	4.4

[a] Alternative requiring 50% SO_2 removal not applicable to HSC boilers since resulting emissions would not meet baseline requirements.

[b] Baseline requires 78.9% SO_2 removal; other alternatives require 90% removal.

[c] Negative numbers indicate net savings.

[d] Normalized total annual cost is total annual cost divided by total annual heat input to boiler ($\$/10^6$Btu).

TABLE 8.2-5. ANNUALIZED COSTS OF LSC MODEL BOILERS[2] (JUNE 1978$)

		Annualized Costs ($1000/yr)[a]						Percent Increase in Costs	
Control Alternative	Model Boiler	Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized[b] Total	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	LSC-30-Unc, Unc, SM	1199	0	0	13.9	1213	7.69	1.2	0
1	LSC-30-Unc, Unc, SSS	1199	0	0	30.0	1229	7.79	2.5	1.3
2	LSC-30-Unc, Unc, FF	1199	0	0	83.4	1282	8.13	6.9	5.7
3	LSC-30-Unc, DS, DS/PM	1199	0	349	w/SO_2	1548	9.82	29.1	27.6
4	LSC-30-Unc, FGD, FGD/PM	1199	0	376	w/SO_2	1575	9.99	31.4	29.8
5	LSC-30-Unc, FGD, FF	1199	0	333	83.4	1616	10.25	34.8	33.2
B	LSC-75-Unc, Unc, SM	2448	0	0	29.1	2477	6.28	1.2	0
1	LSC-75-Unc, Unc, SSS	2448	0	0	58.6	2507	6.36	2.4	1.2
2	LSC-75-Unc, Unc, FF	2448	0	0	169	2617	6.64	6.9	5.7
3	LSC-75-Unc, DS, DS/PM	2448	0	455	w/SO_2	2903	7.36	18.6	17.2
4	LSC-75-Unc, FGD, FGD/PM	2448	0	470	w/SO_2	2918	7.40	19.2	17.8
5	LSC-75-Unc, FGD, FF	2448	0	415	169	3032	7.69	23.9	22.4
B	LSC-150-Unc, Unc, SM	4135	0	0	65.7	4200	5.33	1.6	0
1	LSC-150-SCA, Unc, SSS	4135	5.4	0	115	4255	5.40	2.9	1.3
2	LSC-150-SCA, Unc, FF	4135	5.4	0	295	4435	5.63	7.3	5.6
3	LSC-150-SCA, DS, DS/PM	4135	5.4	621	w/SO_2	4760	6.04	15.1	13.3
4	LSC-150-SCA, FGD, FGD/PM	4135	5.4	622	w/SO_2	4762	6.04	15.2	13.4
5	LSC-150-SCA, FGD, FF	4135	5.4	517	295	4952	6.28	19.8	17.9
B	LSC-400-LEA, Unc, FF	10180	-14.8	0	607	10771	5.12	5.8	0
1	LSC-400-SCA, DS, DS/PM	10180	59.0	1050	w/SO_2	11289	5.37	10.9	4.8
2	LSC-400-SCA, FGD, FGD/PM	10180	59.0	964	w/SO_2	11203	5.33	10.0	4.0
3	LSC-400-SCA, FGD, FF	10180	59.0	756	607	11602	5.52	14.0	7.7

[a] Negative numbers indicate net savings.

[b] Normalized total annual cost is total annual cost divided by total annual heat input to boiler ($\$/10^6$Btu).

TABLE 8.2-6. ANNUALIZED COSTS OF OIL- AND GAS-FIRED MODEL BOILERS[2]
(JUNE 1978 $)

Control Alternative	Model Boiler	Annualized Costs ($1000/yr)[a]						Percent Increase in Costs[b]	
		Uncontrolled Boiler	NO_x Control	SO_2 Control	PM Control	Total	Normalized[c] Total	Over Uncontrolled Boiler	Over Baseline Controlled Boiler
B	RES-30-Unc, HDS(1.6), Unc	1070	0	65.2	0	1136	7.86	6.2	0
1	RES-30-LEA, HDS(0.8), HDS/PM	1070	-5.7	105	w/SO_2	1170	8.09	9.3	3.0
2	RES-30-LEA, HDS(0.3), HDS/PM	1070	-5.7	142	w/SO_2	1210	8.37	13.1	6.5
3	RES-30-LEA, FGD/Na, FGD/PM	1070	-5.7	322	w/SO_2	1386	9.59	29.5	22.0
4	RES-30-LEA, FGD/Na, ESP	1070	-5.7	322	96.1	1482	10.25	38.5	30.5
B	RES-150-Unc, HDS(1.6), Unc	4368	0	326	0	4694	6.50	7.5	0
1	RES-150-LEA, HDS(0.8), HDS/PM	4368	-39.0	526	w/SO_2	4855	6.72	11.1	3.4
2	RES-150-LEA, HDS(0.3), HDS/PM	4368	-39.0	773	w/SO_2	5055	6.99	15.7	7.7
3	RES-150-LEA, FGD, FGD/PM	4368	-39.0	639	w/SO_2	4968	6.87	13.7	5.8
4	RES-150-LEA, FGD, ESP	4368	-39.0	598	225	5153	7.13	18.0	9.8
B	RES-400-LEA, FGD[d], FGD/PM	12472	-108	961	w/SO_2	13325	6.91	6.8	0
1	RES-400-LEA, FGD, FGD/PM	12472	-108	1018	w/SO_2	13382	6.94	7.3	0.4
2	RES-400-LEA, FGD, ESP	12472	-108	952	385	13700	7.11	9.8	2.8
B	DIS-30-Unc, Unc, Unc	1117	0	0	0	1117	9.44	0	0
1	DIS-30-LEA, HDS(0.3), Unc	1117	-0.5	49.7	0	1166	9.86	4.4	4.4
B	DIS-150-Unc, Unc, Unc	5260	0	0	0	5260	7.28	0	0
1	DIS-150-LEA/RAP, HDS(0.3), Unc	5260	71.3	304	0	5635	7.80	7.1	7.1
B	NG-30-Unc, Unc, Unc	970	0	0	0	970	8.20	0	0
1	NG-30-LEA, Unc, Unc	970	-0.7	0	0	969	8.19	negligible	negligible
B	NG-150-Unc, Unc, Unc	4364	0	0	0	4364	6.04	0	0
1	NG-150-LEA/RAP, Unc, Unc	4364	75.9	0	0	4440	6.14	1.7	1.7

[a] Negative numbers indicate net savings.

[b] Negative numbers indicate alternative is less costly than baseline alternative (see text).

[c] Normalized total annual cost is total annual cost divided by total annual heat input to boiler ($\$/10^6$Btu).

[d] 75% efficiency required at baseline.

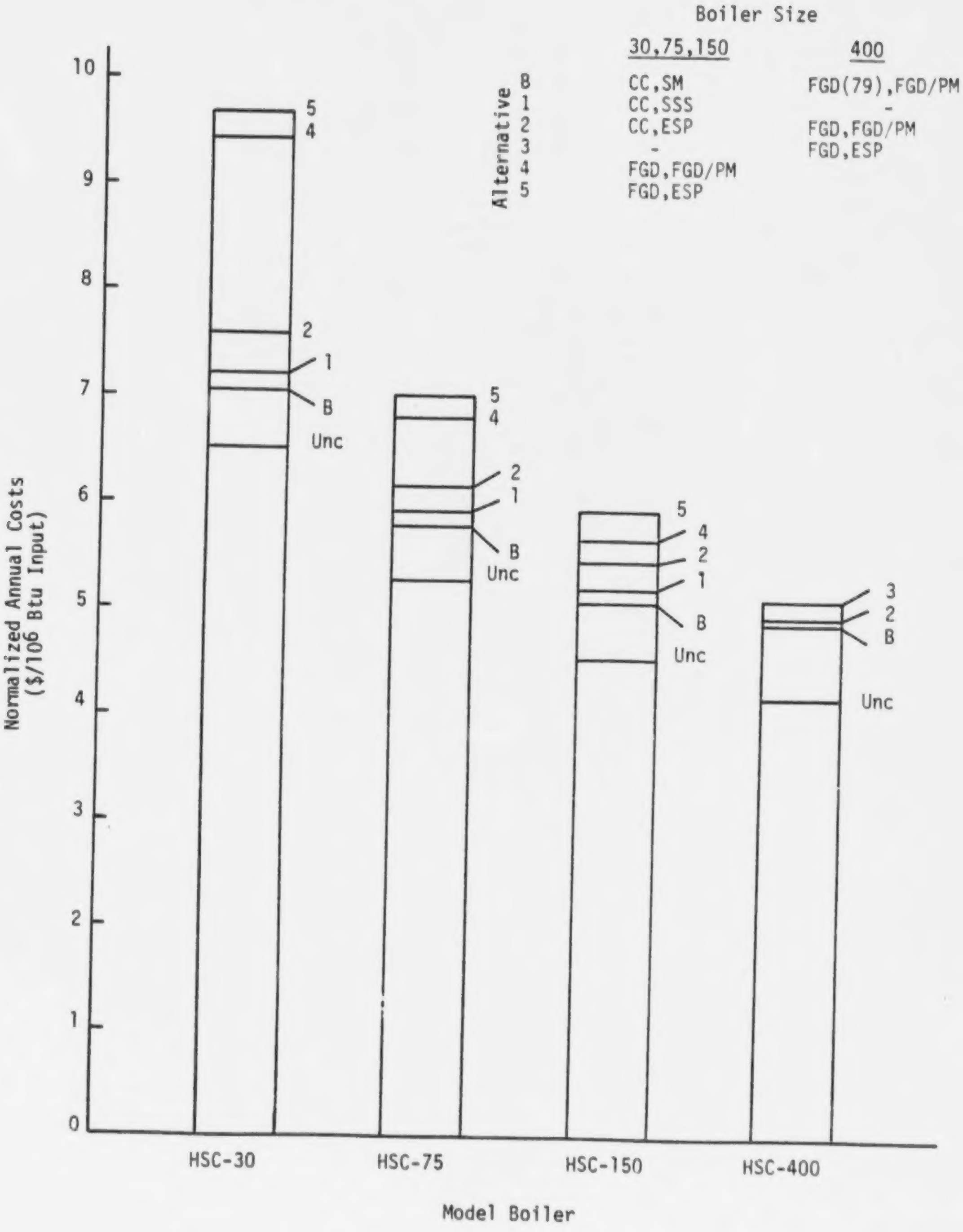

Figure 8.2-4. Annualized costs of control alternatives applied to HSC-fired model boilers. (June 1978$)

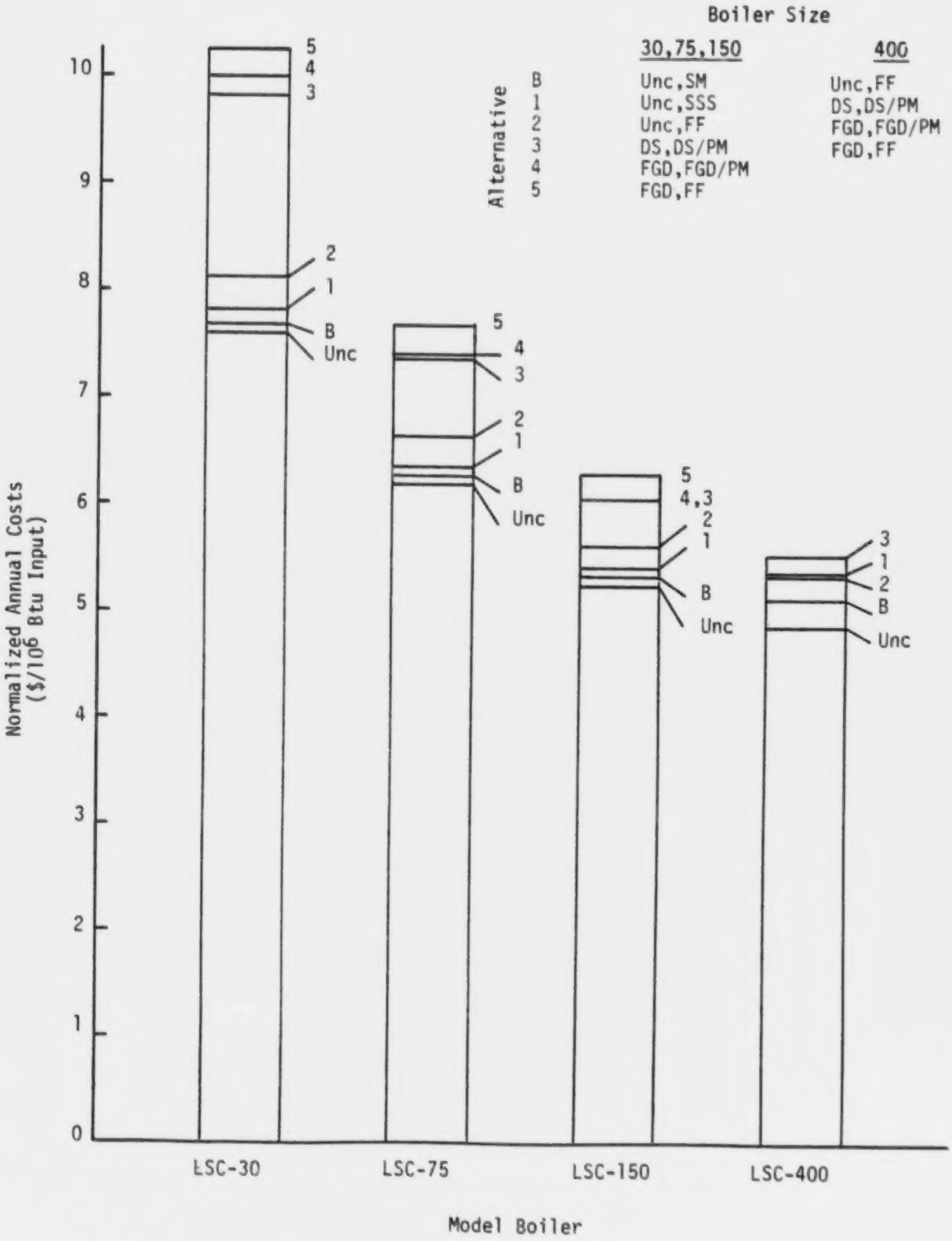

Figure 8.2-5. Annualized costs of control alternatives applied to LSC-fired model boilers. (June 1978$)

and 8.2-5. The small insert tables are repeated from the capital cost tables and provide a key to the technologies used to meet the emission limits specified in each control alternative.

Most of the trends present in the capital cost data are carried over in the annualized costs. In general, the percent increases in annualized cost over baseline are reduced compared to capital cost increases over baseline. This is primarily due to the effect of including relatively high boiler fuel costs in the total annualized cost. Including fuel costs increases the total cost of the uncontrolled boiler; thus, reducing the emission control costs as a percentage of the baseline or uncontrolled boiler cost.

For the HSC model boilers, the sidestream separator control system show a cost advantage compared to ESP systems. Increases in annualized costs over baseline attributable to PM control for Alternative 1 (which requires a sidestream separator) are less than 1.5 percent. Under Alternative 2 (which requires an ESP) PM control costs are increased by 6.0 percent to 7.5 percent. As was mentioned in the discussion of capital costs, the normalized annual cost of ESP control is relatively high at the 44 MW (150×10^6 Btu/hr) boiler size due to the higher uncontrolled emissions of the spreader stoker compared to the smaller boilers.

Percentage cost increases over baseline resulting from PM controls applied to LSC boilers are slightly less than are the increases for the same controls applied to HSC boilers. The primary reason is the higher annual costs for uncontrolled LSC boilers compared to uncontrolled HSC boilers. Alternative 1 annualized cost increases are less than 1.5 percent over baseline, while Alternative 2 cost increases are less than 5.7 percent over baseline for all boiler sizes. The normalized cost of fabric filters does not exhibit the cost anomaly at the 44 MW (150×10^6 Btu/hr) boiler size as was pointed out in the previous discussion of ESP costs. Uncontrolled emissions rates have only a slight effect on fabric filter costs. Therefore, the difference in uncontrolled emissions rates between boiler types has little effect on fabric filter costs.

The annualized costs of SO_2 control account for a higher percentage of total model boiler costs than was the case for capital costs. This results primarily from the higher annualized costs associated with utilization of compliance coal or FGD systems. For the HSC model boilers, the costs of obtaining coals which will meet the 860 ng/J (2.0 lb/10^6 Btu) emission limit specified in Alternatives 1 and 2 is significant, and accounts for 6.6 to 11.1 percent of the uncontrolled boiler annualized costs. However, these costs are still less than FGD costs for boilers with thermal input capacities of 44 MW (150 x 10^6 Btu/hr) or less. Combined SO_2 and PM control systems (Alternative 4) applied to HSC model boilers result in increases in annualized cost over baseline of 12 to 34 percent, with the percentage increasing as the boiler size decreases from 44 to 8.8 MW (150 to 30 x 10^6 Btu/hr). The most expensive control systems for HSC model boilers are the separate SO_2 and particulate matter systems (Alternative 5) which result in annualized cost increases over baseline of from 17 to 38 percent. A comparison of the combined vs. the separate SO_2 and PM control systems applied to HSC model boilers indicates that the separate systems cost 3 to 5 percent more than the combined systems on an annualized basis.

Costs of SO_2 control for LSC model boilers show the same trends as the costs of control for HSC model boilers. However, the percent increases over baseline are somewhat lower for the LSC-fired units. This is to be expected since much of the SO_2 control is inherent in the firing of LSC and the increased cost of this fuel is included in the uncontrolled boiler cost. For a given boiler size, SO_2 control level and type of control system, the total cost of producing steam ($/unit mass of steam) is approximately the same for the LSC and HSC units. Dry scrubbing at 50 percent SO_2 removal (Alternative 3) and double alkali scrubbing at 90 percent SO_2 removal (Alternative 4) have virtually identical costs. The only minor exception is a slight (less than two percent) annualized cost advantage for dry scrubbing at the smallest boiler size. The combined SO_2 and PM systems show cost increases over baseline of 13 to 30 percent for the LSC boilers. The combination of an FGD and a fabric filter results in increases of 18 to 33 percent. (In both cases the percent increases as the boiler size decreases from 44 to 8.8 MW.) The FGD and fabric filter systems cost 2 to 4 percent more than the combined SO_2 and PM systems (FGD or DS) on an annualized basis.

8.2.2.2 Large Coal-Fired Model Boilers. Because of more stringent baseline control requirements, and the economies of scale for large FGD units, annualized cost increases over baseline for large (greater than 73 MW (250×10^6 Btu/hr)) coal-fired boilers are generally less than for the smaller model boilers. For the HSC-400 boiler, increasing SO_2 removal efficiency from the baseline level of 79 percent to 90 percent required under Alternative 2 results in a 1.4 percent increase in annualized costs. Alternative 3 requires separate double alkali FGD and ESP control systems and results in a 4.4 percent increase over baseline for the 117 MW (400×10^6 Btu/hr) unit.

For the LSC model boilers, three alternatives beyond baseline were evaluated. Alternative 1 requires dry scrubbing with 50 percent SO_2 removal while Alternative 2 requires a double alkali combined SO_2 and PM control system with 90 percent SO_2 removal. Consistent with annualized costs of controls for smaller boilers, Alternatives 1 and 2 show approximately equal annualized costs, with increases over baseline of four to five percent for the 117 MW (400×10^6 Btu/hr) boiler. Alternative 3 requires a separate SO_2 and PM control system (FGD plus a fabric filter) and results in the greatest cost impact. The annualized cost increase over baseline for this alternative is 8 percent for the 117 MW boiler.

8.2.2.3. Oil- and Gas-Fired Model Boilers. The annualized costs for residual oil-fired model boilers presented earlier in Table 8.2-6 are graphically illustrated in Figure 8.2-6. NO_x controls are not specified in the insert table. NO_x control costs using combustion modification are generally less than one percent of the total model boiler annualized cost for all boiler sizes.

At the smallest boiler size (8.8 MW or 30×10^6 Btu/hr) application of FGD results in a sharp increase in annualized costs over baseline. At this size, cost increases over baseline for Alternatives 1 and 2, which require HDS cleaned oil, are 3 and 6.5 percent, respectively. Alternative 3, which

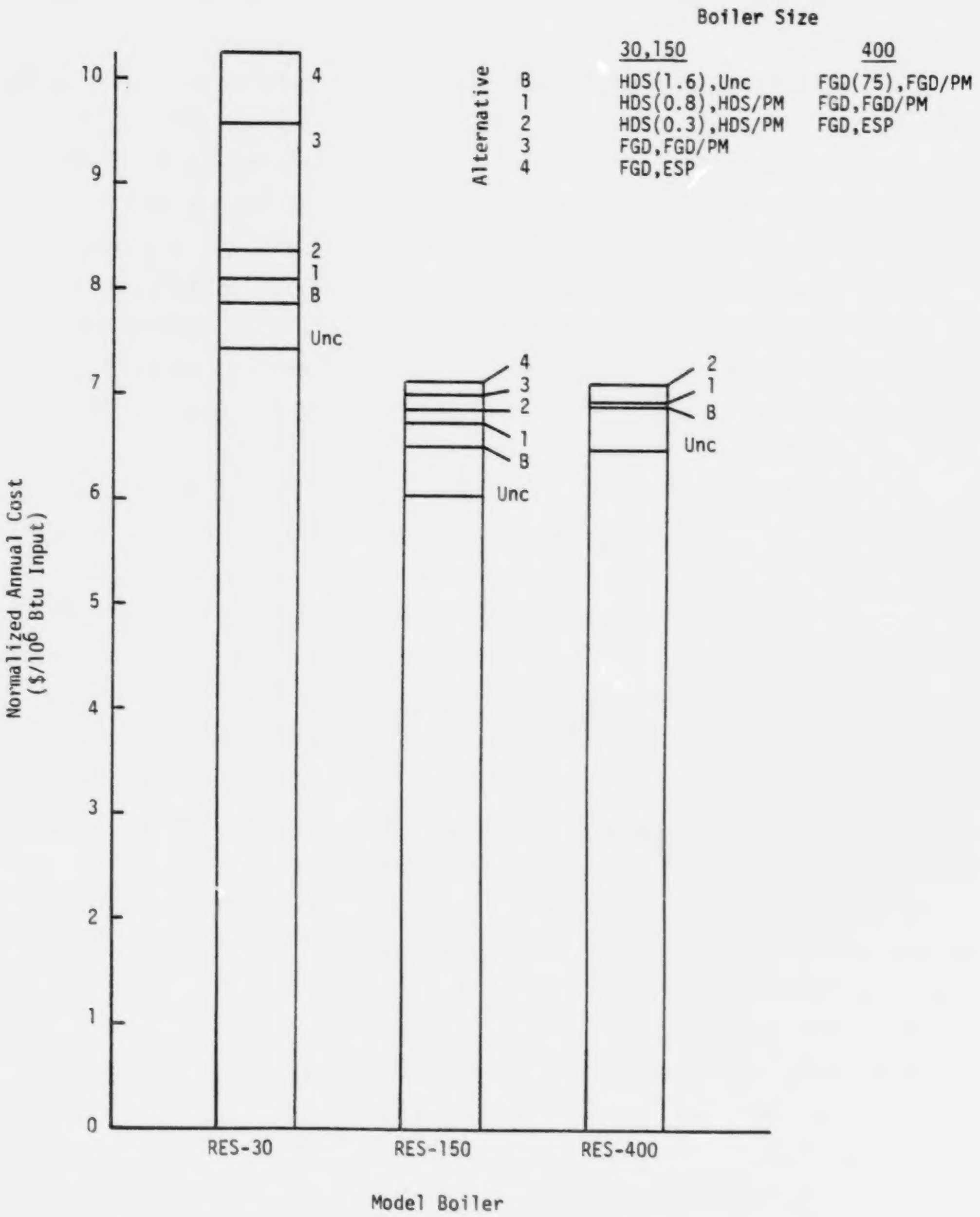

Figure 8.2-6. Annualized costs of control alternatives applied to residual oil-fired model boilers. (June 1978 $)

requires a sodium throwaway FGD scrubber, results in an annualized cost increase over baseline of 22 percent. However, at the 44 MW (150×10^6 Btu/hr) size, the economies of scale of FGD systems tend to make the costs of HDS and FGD comparable. The net result is that annualized costs under Alternative 3 (combined SO_2 and PM FGD system) are slightly less than those for Alternative 2 (HDS cleaned oil). The most expensive emission control system is an FGD system (90 percent SO_2 removal) and an ESP for PM control. This system, required under Alternative 4, results in a 10 percent increase in annualized cost over baseline for the 44 MW (150×10^6 Btu/hr) boiler.

At the 117 MW (400×10^6 Btu/hr) boiler size the baseline alternative requires 75 percent SO_2 removal to meet a 344 ng/J (0.8 lb/10^6 Btu) SO_2 emission limit. A slight (0.4 percent) annualized cost increase is incurred at a 90 percent SO_2 removal level as required under Alternative 1. Double alkali scrubbing with PM removal is used at both the baseline alternative and Alternative 1. To meet the PM emission limit of 11 ng/J (0.05 lb/10^6 Btu) required under Alternative 2, an ESP is required in addition to the double alkali FGD system for SO_2 control. This control scheme results in a 2.8 percent increase in annualized costs over baseline.

The annualized cost data for the distillate oil-fired boilers shown in Table 8.2-6, indicates cost increases over baseline of 4.4 percent and 7.1 percent for the DIS-30 and DIS-150 model boilers, respectively. These cost increases are for the LEA and LEA/RAP systems for NO_x control and use of HDS cleaned oils for SO_2 control. The higher percent increase is associated with the larger boiler. This is due to the HDS costs which are a progressively larger percent of total boiler costs as the boiler size (i.e. fuel consumption) increases.

Costs of NO_x control for natural gas-fired boilers are small. At the 8.8 MW (30×10^6 Btu/hr) size, LEA control results in a negligible annualized cost impact. At the 44 MW (150×10^6 Btu/hr) size, the LEA/RAP control required under Alternative 1 results in a 1.7 percent increase in annualized cost over baseline. No SO_2 or PM controls are used on the natural gas-fired model boilers.

8.2.3 Retrofit Cost Impacts

Under the provisions of 40 CFR 60.14 and 60.15, an "existing facility" may become subject to standards of performance if deemed modified or reconstructed. In such situations control devices would have to be installed for compliance with new source performance standards.

Due to special considerations, the cost for installing a control system in an existing boiler facility is generally greater than the cost of installing the control system on a new facility. Since retrofit costs are highly site-specific, they are difficult to estimate. Examples of these site-specific factors are availability of space and the potential need for additional ducting.

Configuration of equipment in the plant governs the location of the control system. For instance, if the boiler stack is on the roof of the boiler house, the control system may have to be placed at ground level, requiring long ducting runs from the ground level to the stack. If the available space at the plant is inadequate to accommodate the control equipment, it may be necessary to install the equipment on the roof of an adjacent building, thus requiring the addition of structural steel support. It has been estimated that roof top installation can double the structural costs for installation of the control system. Foundations and structural support costs typically amount to 2-3 percent of the control system capital costs.[18]

Other capital cost components that may increase because of space restrictions and plant configurations are contractor and engineering fees (typically 15-25 percent of the control system capital cost),[18] construction and labor expenses, and interest charges during construction (because of longer construction periods).

8.3 OTHER COST CONSIDERATIONS

This section addresses additional cost considerations that may be incurred by boiler operators and/or regulatory agencies that have not been addressed in Section 8.2. Additional cost impacts are likely in two areas:

- Liquid and solid waste disposal, and

- Impact of compliance and reporting requirements.

The major liquid and solid waste streams from an uncontrolled boiler are: water softening sludge, condensate blowdown, bottom ash disposal, and coal pile runoff. Bottom ash collection, handling, and disposal costs have been incorporated into the uncontrolled boiler cost estimates. Bottom ash disposal costs were estimated based on a non-hazardous waste classification under RCRA regulations. If industrial boiler wastes are classified as hazardous in the future, then the disposal costs and overall boiler control costs (for coal-fired boilers) could increase significantly.

Costs for treating the other three waste streams were not quantitatively evaluated in this study. The costs associated with the disposal problems are highly site-specific and are influenced by the following:

- Water softening sludge - raw water quality, steam quality, water makeup rate.
- Condensate blowdown - effluent discharge quality requirements, raw water quality, condensate blowdown quantity.
- Coal pile runoff - coal quality, meterological conditions, effluent discharge quality requirements.

However, these costs would be associated with the boiler itself and would not affect the analysis of incremental cost impacts of air pollution controls.

Impacts of compliance and reporting have been addressed in separate studies.[2]

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9.0 ECONOMIC IMPACT

This chapter presents economic impacts for a range of alternative regulatory options (ARO's) analyzed in the development of the proposed standards for new industrial boilers. The ARO's reflect an upper and lower bound on the stringency of the emission standards which have been studies by EPA. The actual proposed standards resemble most closely the emission regulations analyzed under ARO I (the least stringent ARO), which is outlined below in Section 9.2.1 along with the base case and ARO V (worst case) regulations.

The discussion of impacts for industrial users of steam includes the impacts for both ARO I and V. The results for ARO I are essentially the same as the potential impacts for the proposed standards. The most stringent regulation (ARO V) illustrates a worst case scenario to determine whether potentially severe economic impacts could occur to either the industrial users of steam or the producers of industrial steam-generating and pollution control equipment.

The impact analysis examines cost-related impacts and capital availability issues. Cost-related impacts include impacts on product price, changes in the competitive position of an industry (firm), and closure.

Capital availability issues refer to the ability of a firm to obtain capital to finance the costs of control required by alternative regulatory options.

Because the number of industries that could be affected by the proposed standard is large, a two-fold approach was used to assess the level and nature of the economic impact without undertaking a detailed analysis of every industry. The first component is performed on the general industry level (i.e., food or steel industries) for major steam-using industries. Eight industry groups, which account for approximately 70 percent of total industrial steam consumption and, therefore, which will bear most of the cost burden of alternative regulatory options, are examined.

The second component of the user impact analysis focuses on the economic impact on selected four-digit Standard Industrial Classification (SIC) industries. This focus is necessary since the major steam user analysis utilizes industry averages to assess economic impact. Because each two-digit SIC industry grouping is composed of many four-digit SIC industries, the industry average may not capture the impact of regulatory options on specific four-digit SIC industries. In addition, four-digit SIC industries that are not part of the eight industry groups analyzed under major steam users may be affected severely. To remedy the situation, the economic impact on selected four-digit SIC industries is examined. The industries chosen for this component of the analysis were selected by a screening process designed to identify the four-digit SIC industries most likely to experience adverse economic impacts. By evaluating the economic impact on industry groups most likely to be affected adversely, the impact on other industry groups can be inferred to be less severe.

Chapter organization -- This chapter is presented in two parts. The first section (9.1) presents profiles of the industries that will be covered in the economic impact analysis. The second section (9.2) presents the economic impact analysis of users.

9.1 INDUSTRY ECONOMIC PROFILES

9.1.1 Major Steam Users

9.1.1.1 Introduction. The major steam users consist of the following eight industry groups:

- Food
- Textiles
- Paper
- Chemicals
- Petroleum refining
- Stone, clay, and glass
- Steel
- Aluminum.

These industries are examined because together they account for approximately 70 percent of total industrial steam consumption and, therefore, will bear most of the cost burden of an alternative regulation. Except for steel and aluminum, the industries examined are identified by a two-digit SIC code.

These eight industries generally use approximately 50 percent or more of their energy consumption to generate steam and/or have steam costs that comprise a major percentage of production costs. Table 9-1 shows 1976 total fossil fuel consumption (excluding raw material and feedstock uses) and the percent of total consumption accounted for by boilers in each of the major steam user groups. Approximately 48 percent of all industrial non-feedstock fossil fuel consumption in 1976 was in boilers. The paper, food, and textiles industries consumed significantly more of their fossil fuel in boilers than in other uses; the paper industry consumed approximately 87 percent of its fossil fuel in boilers, the food industry 83 percent, while the textile industry used 80 percent. The chemicals and aluminum industries also were well above the average for industrial boiler fossil fuel consumption.

One indication of the percentage of production costs that accounts for steam generation is the ratio of steam consumption to dollar value of product. This ratio is computed by finding the quotient of annual steam consumption and the value of shipments. Ratios for 1976 values are listed in Table 9-1. The average steam consumption per dollar value of product for industry is 0.0035 GJ (0.0033 MMBtu). Therefore, the average cost of steam per dollar of product for each major steam user depends on the average cost of its steam (i.e., \$/GJ or \$/MMBtu). The paper and chemical industries show the greatest steam consumption per dollar of product at 0.0215 GJ (0.0204 MMBtu) and 0.0160 GJ (0.0152 MMBtu), respectively.

9.1.1.2 Economic Profile. The major steam users represent a large segment of the industrial sector. This subsection shows the relationship of the major steam users to aggregate industry on three measures: value added in manufacturing, number of establishments, and total employment.

Table 9-2 shows the value added by manufacture in each industry for 1976. Value added is the dollar amount by which an industry increases the sum of its material inputs to produce a finished product. The largest value added within the major steam users occurs in the food and chemical industries.

Only 22 percent of the total number of industrial establishments within the United States are accounted for by the major steam users. Of this 22 percent, over three-quarters are food, chemical, and stone, clay, and glass industry establishments.

Major steam users employ about 30 percent of all manufacturing workers. The food industry employs the largest number of employees of the major steam users.

9.1.1.3 Projected Growth. For this analysis, a macroeconomic forecasting model developed by Data Resources, Inc. (DRI) provides projections of industrial economic activity in 1985, 1990, and 1995. The measure of industrial activity is the value added by manufacture statistic. The value added statistic is the difference between the value of shipments and the total cost of materials.

Table 9-3 presents projected value added statistics for the major steam user groups. The chemical industry has the highest projected growth.

TABLE 9-1. FOSSIL FUEL CONSUMPTION CHARACTERISTICS OF THE MAJOR STEAM USERS

SIC Code	Industry	Total fossil fuel consumption[a,b] 10^{12} kJ	Total fossil fuel consumption[a,b] (10^{12} Btu)	Industrial boiler[a] fossil fuel consumption as a percent of total fossil fuel consumption	Steam consumption per[a,c] dollar product: 10^6 kJ per $ value of shipment	Steam consumption per[a,c] dollar product: (10^6 Btu per $ value of shipment)
20	Food	797.8	(756.3)	83	0.0037	(0.0035)
22	Textiles	224.9	(213.2)	81	0.0050	(0.0047)
26	Paper	1,191.9	(1,129.9)	87	0.0215	(0.0204)
28	Chemicals	2,537.2	(2,405.3)	66	0.0160	(0.0152)
29	Petroleum refineries	1,395.3	(1,322.7)	26	0.0042	(0.0042)
32	Stone, clay and glass	1,128.8	(1,070.1)	4	0.0015	(0.0014)
3312, 3315-17	Steel	967.4	(917.1)	30	0.0063	(0.0060)
3334, 3353-55	Aluminum	275.4	(261.1)	64	0.0155	(0.0147)
	Other[d]	2,476.1	(2,347.3)	32	0.0008	(0.0008)
	Total	10,994.7	(10,423.0)	48	0.0035	(0.0033)

[a] Energy and Environmental Analysis, Inc. The Industrial Sector Energy Consumption Data Base (ECDB) for 1975 and 1976. December 15, 1980.

[b] Excludes raw materials, feedstock, and use in vehicles. Includes coal, distillate and residual fuel oil, and natural gas.

[c] U.S. Department of Commerce, Bureau of the Census. Annual Survey of Manufactures. 1976.

[d] Includes agriculture, mining, miscellaneous manufacturing, and construction industries.

TABLE 9-2. CHARACTERISTICS OF THE MAJOR STEAM USERS

SIC Code	Industry	Value added by manufacture[a]		Number of establishments[a]		Total employment[a]	
		10^6 $	Percent of total	Number	Percent of total	10^3	Percent of total
20	Food	52,760	10	24,113	8	1,535.8	9
22	Textiles	14,495	3	6,580	2	875.9	5
26	Paper	20,604	10	5,891	2	614.9	3
28	Chemicals	51,408	10	11,032	4	850.9	5
29	Petroleum refineries	13,169	3	1,982	1	144.4	1
32	Stone, clay and glass	16,773	3	15,713	5	598.9	3
3312, 3315-17	Steel	16,984	3	1,110	1	523.8	3
334, 3353-55	Aluminum	3,371	1	304	1	26.3	1
	Other	321,907	63	243,908	78	12,511.0	71
	TOTAL	511,471	100	310,633	100	17,681.9	100

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[a] U.S. Department of Commerce, Bureau of Census, 1976.

TABLE 9-3. INDUSTRIAL PRODUCTION GROWTH RATE PROJECTIONS[a]

Industry	Value added (10^9 $ 1975)				Annual growth rate (%)[b]		
	1974	1985	1990	1995	1974-85	1986-90	1991-95
Food	50.2	69.7	79.2	88.3	1.3	2.6	2.2
Textiles	N.A.	N.A.	N.A.	N.A.	3.1[c]	4.1[c]	3.0[c]
Paper	21.9	25.3	29.5	33.3	1.3	3.2	2.5
Chemicals	50.9	76.1	94.8	112.1	3.7	4.5	3.4
Petroleum refineries	8.0	8.8	8.9	9.1	0.9	0.4	0.5
Stone, clay & glass	16.6	22.7	26.9	28.3	2.8	3.5	1.0
Primary metals	43.1	36.5	42.0	44.8	(0.2)	2.8	1.3

[a] Data Resources, Inc. TRENDLONG.2005 Forecast, December 1980 (Department of Energy, Energy Information Administration's Annual Report to Congress 1980, Medium Case).

[b] Average compound annual increase.

[c] Growth rate projections for other manufacturing.

9.1.2 Selected Industries

This section contains profiles of the seven four-digit SIC industries selected for analysis. Due to the large number of four-digit SIC industries, screening criteria were used to target those industries most likely to experience cost-related impacts and/or capital availability constraints.

Industries most likely to experience cost-related impacts are those with a high steam cost to production cost ratio. A high ratio usually stems from one of two factors: 1) the production process is steam-intensive or 2) the firm or industry has cyclic steam requirements, resulting in a low capacity utilization of the boiler equipment. Low capacity utilization causes the capital cost component of unit steam costs to rise, yielding high annualized costs per unit of steam. Therefore, capacity utilization and percentage of steam costs to total product costs are used as selection criteria.

Capital availability constraints occur when the cost of acquiring funds is so high that a firm considers a project to be uneconomic or financially unattractive. Capital availability is most often a problem for relatively small firms. Although some large firms may have excessive debt burdens, lack of access to organized capital markets is more often characteristic of small firms. Thus, size is used to identify firms with potential capital availability problems.

The following seven four-digit SIC industries are profiled in this section:

- Beet sugar refining
- Fruit and vegetable canning
- Rubber reclaiming
- Automobile manufacturing
- Petroleum refining.
- Iron and steel manufacturing
- Liquor distilling.

Each profile contains an industry description and a discussion of recent production trends.

9.1.2.1 Beet Sugar Refining Industry. The U.S. beet sugar refining industry (SIC 2063) is characterized by relatively few producers. Twelve companies operate 44 refineries generally located in the midwestern and Pacific States.[1]

Refining operations are highly seasonal, usually commencing in mid-September and ending by mid- to late March. The length of the refining season varies from 120 to 220 days, depending on beet crop conditions. During the average refining season of 180 days, plants operate 7 days a week, 24 hours a day. Annual capacity utilization of boilers at a plant is typically in the range of 30 to 45 percent.

In recent years, the annual total output of the beet sugar industry has been decreasing. The number of plants in the industry also has decreased; firms have closed less profitable plants, run operations as a cooperative (i.e., where the firm is owned by the sugar beet farmers) or, as a last resort, entirely terminated operations.

The major explanation for decreased production is the increasing level of cane sugar imports, which in 1978 accounted for over 45 percent or 4.5 million megagrams (5 million tons) of total U.S. sugar demand. In the same year, domestic beet sugar production claimed only 32 percent or 3.2 million megagrams (3.5 million tons) of demand.[2] In view of this foreign competition, American firms must keep their prices aligned with world sugar prices. Although substitutes for sugar exist in the form of highly concentrated fructose, the beet sugar industry maintains that foreign imports pose the greater threat to solvency.

Between 1974 and 1978, world and U.S. sugar prices fluctuated widely, ranging from $0.18 to $1.43 per kilogram ($0.08 and $0.65 per pound) of refined sugar.[3] Record prices were set in 1974 because of the world sugar beet crop shortage. The price of sugar for 1979 production was $0.40 per kilogram ($0.18 per pound).

Production of beet sugar increased significantly in the post-sugar shortage years. Since 1976, however, total production has decreased due to plant shutdowns and decreased production per plant. In addition, total sales and sales per plant have decreased steadily during the 1975 to 1978 period.

Due to highly volatile prices and declining sales, most domestic producers are not considering expansion. Instead, they are focusing on plant (and boiler) maintenance and/or replacements as well as company consolidations when economically practical. Due to the industry's small profit margin, only the larger, more profitable firms that benefit from economies of scale would consider investing in a boiler replacement.

9.1.2.2 Fruit and Vegetable Canning Industry. The fruit and vegetable canning industry (SIC 2033) is highly competitive; hundreds of firms operate over 500 canneries which are located in the fruit and vegetable growing areas of the United States and which specialize in canning local raw produce. California has the highest concentration of canneries -- accounting for 45 percent of domestically produced canned goods -- and is followed closely by States in the northeastern and midwestern regions. Despite this production concentration, canneries exist in almost every State of the nation.[4]

Fruit and vegetable canneries have highly seasonal production patterns. The peak of the canning season is reached at the end of the growing season -- in late summer and early fall. Although the range of operations varies with each cannery, the average plant cans fruits and vegetables approximately 120 days per year. Some plants have secondary, non-seasonal product lines produced during the "off" season that help decrease average fixed production costs.

In recent years, the number of firms in the fruit and vegetable canning industry has declined as large corporations acquire smaller firms. In fact, the canning industry is characterized by large numbers of small canneries competing with a growing number of large canneries. The canning industry is consolidating for several reasons. First, diversification of a company's product line eases fluctuations in sales and product price and, hence, profit. Second, product diversification, or canning produce with varying processing seasons, tends to increase the capacity utilization of a company's plants.

The most intense product competition to the canning industry stems from two domestic markets: fresh fruits and vegetables and frozen fruits and vegetables. The perishable nature of fresh produce renders that market a less direct threat to the canning industry than frozen fruits and vegetables. Unlike canned goods, processing frozen items requires only minimal cooking, resulting in more flavor and enhanced product quality.

Fruit and vegetable canning is an unpredictable industry. Variables such as weather conditions and crop yields dictate a cannery's profitability each year. Unseasonable frost, insufficient rainfall, and poor crop planning can restrict the supply of fresh produce available for canning. These factors resulted in price fluctuations and production swings between 1974 and 1978. Total production of canned fruits and vegetables decreased from 581,383,000 cases in 1974 to 516,034,000 cases in 1976. Production in 1977 increased, however, to 548,728,000 cases.[5]

Similarly, total sales and sales per plant in 1974 were high, totaling \$3.4 billion and \$6.6 million, respectively. These amounts decreased in 1975 and 1976 to a low of \$2.98 billion total sales and \$5.72 million sales per plant. By the end of 1977, total sales and sales per plant began to increase, approaching the 1974 level.[6]

9.1.2.3 Rubber Reclaiming Industry. The rubber reclaiming industry (SIC 3031) consists of eight producers operating eight manufacturing establishments.[7] Although the bulk of reclaiming occurs in Ohio, manufacturing plants are located throughout the eastern States. This geographic distribution is explained partially by the availability of energy supplies and the relative proximity to the tire and automotive industries.

Rubber reclaimers buy old rubber tires, inner tubes, and other scrap rubber materials and recycle them into a reusable form of rubber, notably tires and floor mats. Approximately 60 percent of all reclaimed rubber is used in tire manufacturing.[8] For several manufacturers, unmolded reclaimed rubber is the sole output, while for others, especially the larger integrated firms, unmolded recycled rubber is not a primary product but part of an internal subprocess producing various rubber goods.

For the past decade, the rubber reclaiming industry has suffered from volatile sales, production fall-offs, and plant reductions. A series of external factors account for these conditions. More stringent ceilings on the amounts of reclaimed rubber allowed in car tires have been the largest obstacle to the industry's expansion. With the increasing popularity of radial tires, which contain a much smaller percent of reclaimed rubber than standard ply tires, reclaimed rubber consumption has decreased. Although reclaimers still are heavily involved in tire manufacturing (e.g., farm equipment), their importance in the passenger tire market has lessened.

American reclaimers face little product competition from foreign producers, because only a small amount of reclaimed rubber is imported from overseas. Instead, the major competitors are two higher quality substitutes: new, domestically produced synthetic rubber and imported natural rubber.

Industry production fluctuated during the 1974-1978 period. In 1974, production was relatively high at 143,330 megagrams (168,900 short tons).

The following year, industry production decreased by 49 percent to 78,200 megagrams (86,200 short tons). Since 1975, total production climbed gradually, reaching 119,200 megagrams (131,400 short tons) in 1978.[9] Production per plant followed a similar trend.

Prior to 1973, the price of reclaimed rubber fluctuated only slightly. Prices remained around the 1967 base year price of $0.25 per kilogram ($0.11 per pound). In 1973-1974, increasing input costs, such as increasing fuel import prices and rising transportation and collection costs of scrap rubber, began exerting upward pressure on industry price levels. By 1978, the price of reclaimed rubber was $0.37 per kilogram ($0.17 per pound).[10]

After an initial fall in 1975, total sales and sales per plant have risen gradually. Although production per plant in 1978 was significantly less than that in 1974, nominal sales per plant in 1978 were higher ($5.56 million versus $5.34 million). With production dropping, selling prices fluctuating, and production costs mounting, the industry is not considering expanding productive capacity, but instead is using available funds to replace capital assets.

9.1.2.4 Automobile Manufacturing Industry. The U.S. automobile manufacturing industry (SICs 3711, 3713, and 3714) consists of four firms engaged in manufacturing and assembling "American-made" vehicles. These vehicles are produced in many States (and sometimes in other countries), with the majority of production occurring in Michigan, Missouri, Ohio, California, New Jersey, and Wisconsin.

In addition to producing automobiles, the four manufacturing firms produce light trucks, commercial trucks, buses, and other motor vehicles. The following description focuses on the domestic automobile segment of the motor vehicle industry, which accounts for approximately 75 percent of industry production.

The profitability of the automobile industry is affected by the economies of scale realized by each firm in its manufacturing process. Economies of scale in the automotive manufacturing industry occur when a firm produces enough automobiles to decrease the fixed cost per unit output and, consequently, total costs per unit output. The most efficient way for a firm to capture economies of scale is to integrate vertically its production process. The level of integration differs by firm, ranging from minimal levels to near total integration. A firm with minimal integration could produce one or two of the components needed, such as the engine or alternator, as well as assemble the automobile. A totally integrated firm could produce all of the major automobile components as well as the inputs used in producing these components, e.g., steel, glass, plastics. Such a firm would tend to be larger and more productive than a less integrated firm.

The profitability of automobile manufacturers and new car dealers also depends upon consumer demand for automobiles. Manufacturers attempt to stimulate demand for their products by producing more than one car class. Many assembly lines are geared to producing many different models in different price ranges at the same assembly plant. This allows the manufacturer to produce more low-priced cars or more high-priced cars, depending on consumer demand.

Since 1975, total production and production per plant have increased. The average price of new cars for the four domestic manufacturers rose from $4,202 in 1974 to $6,249 in 1978, an annual compounded increase in average sales price of 10.4 percent per year.[11]

Except for the industry leader, the market shares of all domestic manufacturers declined between 1974 and 1978, due to the increased market share of the dominant domestic producer as well as the increased sales of imported automobiles. The share of total sales accounted for by imports increased by about one-third between 1974 and 1977, from 13.8 percent to 18.3 percent.[12]

9.1.2.5 Petroleum Refining Industry. The petroleum refining industry (SIC 2911) consists of 153 companies operating 289 domestic refineries.[13] Of these firms, 19 control over 70 percent of the U.S. refining capacity.

Although refineries operate in 41 States, approximately 27 percent of the crude distillation capacity is concentrated in Texas. California and Louisiana, the second and third largest petroleum refining States, respectively, jointly account for another 27 percent of crude distillation capacity.

While U.S. production of refined oil remained relatively constant at 3.0 to 3.1 billion barrels per year between 1974 and 1978, consumption has increased. Domestic consumption of crude oil for 1978 equaled 6.9 billion barrels or more than twice the amount of crude oil refined domestically.[14] Consequently, the United States depends on imported sources of refined oil.

The U.S. petroleum refining industry suffers from an operating cost disadvantage when compared to European oil companies. U.S. oil companies face higher taxes and labor costs than their European counterparts. This partially explains why the United States imports such a large share of its oil requirements in the form of refined products (as opposed to crude). Consequently, almost 27 percent of world refinery capacity additions are taking place in Europe, while the United States accounts for only 0.9 percent.[15]

Production per plant decreased slightly during the 1974-1978 period. In 1974, average production per plant was 12.06 million barrels per year; by 1978, this average fell to 10.85 million barrels. One explanation for this decrease is the addition of 30 new plants in the past 5 years without a corresponding increase in total production.[16] It appears that new plants are being built with a certain amount of planned excess capacity. Future petroleum refining growth is expected to be concentrated in utilizing excess capacity.

The price of and total revenue from refined petroleum products has almost doubled from 1974 to 1978. The rise in crude oil costs accounts for most of the recent increases in refined product prices and the corresponding value of their sales. Total sales in this period have increased from $54.8 billion to $105.6 billion. Sales per refinery have increased over 70 percent from $211 million to $365 million.

Production capacity in the U.S. petroleum refining industry is projected to grow at a rate of 1.73 percent per annum.[17] Using this figure as an estimate of the level of expansion within the industry, it appears that the petroleum refinery industry could invest in new boilers for both expansion and replacement purposes.

9.1.2.6 Iron and Steel Manufacturing Industry. The iron and steel industry (SIC 3312) consists of integrated establishments that produce basic steel shapes in the form of semi-finished products such as ingots, billets, blooms, and slabs or finished products such as steel strips, bars, shapes, heavy structurals, and rails. Establishments primarily engaged in producing finished products from purchased iron and steel (e.g., non-integrated) are considered separate industries and are classified under SIC codes 3315, 3316, and 3317.[18]

Typically, operations at integrated steel works involve manufacturing iron from raw materials, refining the iron into steel, casting and milling the steel into semi-finished shapes, and either selling the shapes to non-integrated finishing facilities or hot rolling into finished products at the works.[19] Integrated steel works range in size from large plants using several steel-making processes and finishing mills to small plants using a single process and selling a semi-finished product.

The industry is dominated by a few major producers. The seven largest companies produce approximately 70 percent of all domestic steel. The remaining 30 percent is produced by numerous smaller companies, many of which operate only one facility. There are about 260 integrated iron and steel establishments, spanning 36 States,[20] most of which are located in the middle Atlantic and northeastern central regions. The States with the highest concentrations are Pennsylvania, Ohio, Indiana, Illinois, and Michigan. With the exception of Michigan, these States are all major coal producers. Locating plants close to coal regions reduces the expense of obtaining coal that is used extensively in steel making.[21]

Over the last decade, the steel industry has suffered from recessionary trends rooted in the 1950's. Spiraling costs and restrained prices have reduced industry profits to low levels, leaving major steel producers with little capital for maintenance or expansion. As a result, domestic steel producers have been postponing large capital commitments, closing or selling unprofitable operations, reducing production levels, and merging with other companies.

The steel industry attributes its profit deterioration to several factors, the most important of which is the increasing amount of low-cost foreign steel on the domestic market. Over the last 5 years, imports have increased from 13 to 18 percent of total domestic steel demand.[22] In 1978, almost 1 of every 5 megagrams of steel used in the United States was produced outside of the country. Many steel manufacturers claim foreign steel is being dumped on the U.S. market and have responded by discounting their steel prices. Other factors cited by industry are costs to meet environmental and safety standards, inflationary wage and energy costs, and government restraint of steel prices, including direct price controls from 1971 to 1974.[23] Low steel prices have caused the industry to absorb increased costs rather than pass them on to the consumer.

Steel production from 1974 to 1978 was volatile, while prices increased steadily after controls expired in 1974. Because steel inventories were in short supply throughout the world in 1974, domestic steel production was high. Prices were low due to price controls, causing total sales to mask this healthy production. In 1975 and 1976, demand for steel was significantly lower, causing production to decrease. Then, in 1977 as costs increased markedly, imports flooded the domestic market and the steel industry experienced losses for the first time since the 1930's. An upturn in the industry's economic profile took place again in 1978 due to a higher production level and rising prices. In 1978, the steel industry operated at 86.8 percent of capacity compared to the low levels (78.4 percent) in 1977.[24]

Most of the capital investments made in recent years have been piece-meal expansions and replacements rather than large-scale capacity additions or new plants. Projects have attempted to cut costs by improving productivity, or boosting yields through modernization. New plants may be needed to meet projected demand for steel in the 1980's, but it is uncertain whether steel manufacturers will have the discretionary income to make costly investments. It is likely that future investments will follow the same route of piece-meal expansions and replacements unless present market conditions improve.

9.1.2.7 Liquor Distilling Industry. The liquor distilling industry (SIC 2085) is made up of those establishments that manufacture liquor by distillation or rectification. They produce cordial and alcoholic cocktails by blending processes or by mixing liquors and other ingredients. All liquors except brandy are included in this category.

The liquor distilling industry is comprised of approximately 50 firms that operate 100 distilleries.[25,26] The greatest concentration of distilling plants is located in the east south central States, Federal Region 4. While distilleries are located in 25 States, Kentucky has 27 percent of the total number of domestic plants. California follows second with 11 percent of the total.[27]

The number of plants that these firms operate has decreased in recent years. In 1972, 121 distilleries were operating; by 1977, this sum had fallen to 104, a loss of 17 distilleries in 5 years.[28] Apparently, no new facilities have been constructed in recent years. Several factors may explain the decreasing number of operating distilleries: some plants are old, inefficient, and not equipped for the major production modifications often necessary to satisfy the demands of a changing market; furthermore, larger firms often find operating fewer plants more efficient.

The liquor distilling industry has much intra-industry, as well as inter-industry, competition. Intra-industry competition is seen in growth rate and market share statistics of industry segments. During the period 1960-1978, growth rates within the industry segments varied. The cocktails and mixed drinks segment increased at an annual rate of 15 percent during the years studied; cordials and liquors grew 9 percent annually; "white" goods (e.g., vodka, gin) grew at a 7.5 percent rate; and "brown" goods (e.g., whiskey, bourbon) increased moderately at 1 percent annually.[29]

The major inter-industry competition to the distilled spirits industry arises from the beer and wine industries. Beer and wine consumption has grown at the expense, to some degree, of "hard" liquors. Intensive advertising campaigns and brand proliferation has helped beer consumption grow. Wine, especially white wine, once just a dinner beverage, has become a cocktail beverage as well.

With the exception of 1976, total industry output grew consistently each year during the 1974-1978 period. In 1974, bottled output was 1,339.6 million liters (353.9 million gallons); by 1978, industry output reached 1,483.4 million liters (391.9 million gallons), a 9.7 percent increase in 5 years. Output per plant increased steadily from 11.2 million liters (2.9 million gallons) in 1974 to 14.3 million liters (3.8 million gallons) in 1978. The weighted average producer price of distilled spirits in 1974, as reported by the Bureau of Labor Statistics, was $1.31 per liter ($4.95 per gallon). By 1978, the price grew to $1.66 per liter ($6.27 per gallon), a 27 percent increase or 6.6 percent annually. Industry sales volume is derived from total output and price per liter (gallon). Due to price increases, total sales have increased at a greater rate than total output. During 1974 to 1978, total sales grew from $1.75 billion to $2.46 billion, an increase of 40 percent. Similarly, sales per plant grew from $14.60 million in 1974 to $23.63 million in 1978.

The selling price of some distilled liquors normally reflects production costs incurred several years prior to sale. The time lag between production and maturation of whiskey can range from 2 to 8 years, depending upon the quality of the product desired. Therefore, higher manufacturing costs incurred in one year may be reflected in higher prices in subsequent years.

9.2 ECONOMIC IMPACT ANALYSIS

9.2.1 Regulatory Options

Three regulatory cases are considered in the economic impact analysis: the results of two regulatory options are compared against a third case composed of current emission regulations. Current emission regulations are the current New Source Performance Standards (NSPS) for industrial boilers with heat input capacity greater than 73 MW (250 MMBtu/hr) and State Implementation Plan (SIP) emission regulations for all smaller boilers. Large boilers also are subject to SIPs when these regulations are more stringent than the NSPS. Current emission regulations, presented in Table 9-4, hereafter are referred to as the base case.

Regulatory Option I, summarized in Table 9-5, requires coal-fired boilers between 15 and 44 MW (50 and 150 MMBtu/hr) to meet a 43 ng/J (0.1 lb/MMBtu) emission limit for particulate matter (PM) and a 258 ng/J (0.6 lb/MMBtu) emission limit for nitrogen oxides (NO_x). Because no sulfur dioxide (SO_2) regulation is specified, the coal-fired boilers between 15 and 44 MW (50 and 150 MMBtu/hr) are subject to SO_2 SIP's. Coal-fired boilers between 44 and 73 MW (150 and 250 MMBtu/hr) are subject to a 860 ng/J (2.0 lb/MMBtu) emission limit for SO_2 and a 43 ng/J (0.1 lb/MMBtu) emission limit for PM. Stokers in this size category are subject to a 258 ng/J (0.6 lb/MMBtu) emission limit for NO_x; pulverized coal boilers are subject to a 301 ng/J (0.7 lb/MMBtu) emission limit. Coal-fired boilers with heat input capacity greater than 73 MW (250 MMBtu/hr) are required to reduce SO_2 emissions by 90 percent and cannot have an SO_2 emission rate that exceeds 430 ng/J (1.0 lb/MMBtu). Because no minimum percent reduction is required, SO_2 emissions need be reduced only to meet the floor which is 258 ng/J (0.6 lb/MMBtu). The PM emission limit for the larger boilers is 22 ng/J (0.5 lb/MMBtu); the NO_x emission limit is 301 ng/J (0.7 lb/MMBtu).

Regulatory Option V,[*] summarized in Table 9-6, requires that boilers between 15 and 73 MW (50 and 250 MMBtu/hr) reduce SO_2 emissions by 90 percent and that the SO_2 emission rate not exceed 860 ng/J (2.0 lb/MMBtu). If 90 percent reduction results in an emission rate below 258 ng/J

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[*] Regulatory Options I and V are used to bound the analysis of economic impacts.

(0.6 lb/MMBtu), emissions need to be reduced by less than 90 percent, though a minimum of 50 percent reduction is required. These boilers are subject to a 43 ng/J (0.1 lb/MMBtu) PM emission limit. Stokers in this size category are subject to a 258 ng/J (0.6 lb/MMBtu) emission limit for NO_x; pulverized coal boilers are subject to a 301 ng/J (0.7 lb/MMBtu) emission limit. Coal-fired boilers with heat input capacity greater than 73 MW (250 MMBtu/hr) are subject to an SO_2 regulation similar to the one covering boilers between 15 and 73 MW (50 and 250 MMBtu/hr). The only variation is with respect to the maximum SO_2 emission limit. For boilers between 15 and 73 MW (50 and 250 MMBtu/hr), the SO_2 emission rate cannot exceed 860 ng/J (2.0 lb/MMBtu); for boilers greater than 73 MW (250 MMBtu/hr), the SO_2 emission rate cannot exceed 430 ng/J (1.0 lb/MMBtu). The PM emission limit for the larger boilers is 22 ng/J (0.05 lb/MMBtu); the NO_x emission limit is 301 ng/J (0.7 lb/MMBtu).

The emission regulations for natural gas are the same for Regulatory Options I and V: they consist of a NO_x emission limit of 86 ng/J (0.2 lb/MMBtu) for boilers greater than 15 MW (50 MMBtu/hr). Distillate and coal-fired boiler regulations in Tables 9-5 and 9-6.

9.2.2 Major Steam Users

The economic analysis of the major steam users focuses on cost-related impacts. Capital availability considerations are best examined on a firm level and, therefore, are covered only in the analysis of selected industries in Section 9.2.3.

The economic analysis of the major steam users is designed to determine the effect of the regulatory options upon the major industrial steam users. As in Section 9.1.1, the major steam users consist of the following eight industry groups: food; textiles; paper; chemicals petroleum refining; stone, clay, and glass; steel, and aluminum.

These industries account for approximately 70 percent of total industrial steam consumption and, therefore, will bear most of the cost burden of a regulatory option. A profile of the major steam users is presented in Section 9.1.1.

TABLE 9-4. **BASE CASE AIR EMISSION REGULATIONS**
(ng/J)
[(lb/MMBtu)]

	Fuel type	Coal			Residual oil			Distillate oil			Natural gas
	Boiler size, MW (MMBTU/HR)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (>250)	≥15 (≥50)
Pollutant	SO_2	SIP's		**516** (1.2)	SIP's		**344** (0.8)	—	—	**344** (0.8)	—
	PM	SIP's		**43** (0.1)	SIP's		**43** (0.1)	—	—	**43** (0.1)	—
	NO_x	SIP's		**301** (0.7)	SIP's		**129** (0.3)	—	—	**129** (0.3)	**86** (0.2)

TABLE 9-5. **REGULATORY OPTION I**
(ng/J)
[(lb/MMBtu)]

	Fuel type	Coal			Residual oil			Distillate oil			Natural gas
	Boiler size, MW (MMBTU/HR)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (>250)	≥15 (≥50)
Pollutant	SO2	SIP's	860 (2.0)	90% reduction, 430 (1.0) ceiling, 258 (0.6) floor.	SIP's	344 (0.8)		SIP's	150 (0.35)		—
	PM	43 (0.1)		22 (0.05)	43 (0.1)			—			—
	NOx	258/301 (0.6/0.7)*			129 (0.3)			86 (0.2)			86 (0.2)

* 258 (0.6) for stokers, 301 (0.7) for pulverized coal boilers.

TABLE 9-6. **REGULATORY OPTION V**
(ng/J)
[(lb/MMBtu)]

	Fuel type	Coal			Residual oil			Distillate oil			Natural gas
	Boiler size, MW (MMBTU/HR)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (≥250)	15–44 (50–150)	44–73 (150–250)	≥73 (>250)	≥15 (≥50)
Pollutant	SO_2	**860** (2.0) and 90% reduction, if emissions <**258.0** (0.6) 50% reduction.		**430** (1.0) and 90% reduction, if emissions < **258** (0.6) 50% reduction	**344** (0.8)			**150** (0.35)			—
	PM	**43** (0.1)		**22** (0.05)	**43** (0.1)			—			—
	NO_x	**258/301*** (0.6/0.7)*			**129** (0.3)			**86** (0.2)			**86** (0.2)

* **258** (0.6) for stokers, **301** (0.7) for pulverized coal boilers.

9.2.2.1 Methodology of Economic Impact Analysis. The analysis of major steam users consists of four steps:

- Step One -- Evaluate price impacts of alternative regulatory options on a general industry level assuming the costs of the regulatory option are passed completely to the consumer (i.e., full cost pass-through).
- Step Two -- If price impacts are significant, evaluate the ability of the industry to pass through the additional costs.
- Step Three -- If industry is able to pass through costs, assess the macroeconomic impacts of the price increase. If industry is unable to pass on the additional costs, assess the ability of the industry to absorb the additional costs.
- Step Four -- If cost impacts are significant and the industry is unable to absorb the costs, further analysis is warranted for the impact on both the other industries (non-major steam users) and two-digit SIC industries.

The first step of the analysis evaluates the price impacts of alternative regulatory options on major steam users. When price impacts are determined to be significant, they are evaluated in terms of the conditions contained in Steps Two through Four.

The effect of a regulatory option on product price is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the regulatory option, and the amount of steam consumed per dollar of output (see Figure 9-1). The cost impacts are stated in real terms. The only real cost increase is assumed to be due to new boiler, pollution control, and fuel costs. All other production costs are held constant in real terms.

When regulatory options are applied, the first component of the product price calculation (the change in the cost of new steam) is affected. The cost of new steam changes due to an option's effect upon annualized boiler and pollution control capital costs, annualized non-fuel operating and maintenance (O&M) costs, and annualized fuel costs. When this new steam cost change is multiplied by the ratio of annual steam consumed (per unit of output) to annual dollar value of shipment (per unit output), a gross change in product price is derived. Because a certain percentage of the product is produced with steam generated from existing boilers, the cost estimate is reduced by the proportion of new boiler steam to total steam used within each industry group, which results in an average steam cost for

FIGURE 9-1. CHANGE IN PRODUCT PRICE DUE TO REGULATORY OPTION

$$\blacktriangle \text{Product Price} = \left\{ \left(\frac{\text{GJ (MMBtu) Steam}}{\text{Product Price}} \right) \bullet \left(\begin{array}{c} \text{Steam} \\ \text{Affected By} \\ \text{Regulatory} \\ \text{Option} \end{array} \right) \right\} \bullet \left\{ \left(\begin{array}{c} \text{Cost of} \\ \text{New Steam} \end{array} \right)_{\text{Regulatory Option}} - \left(\begin{array}{c} \text{Cost of} \\ \text{New Steam} \end{array} \right)_{\text{Current Regulation}} \right\}$$

- GJ (MMBtu)/Steam Product Price

$$\frac{\text{Annual GJ (MMBtu) Steam/Annual Output (Total Number of Units)}}{\text{Annual \$ Value of Shipments/Annual Output (Total Number of Units)}}$$

- Steam Affected by Regulatory Option

$$\frac{\text{Steam Consumption Affected by Regulatory Option}}{\text{Total Steam Consumption}}$$

- Cost of New Steam

$$\frac{\text{Total Annualized Cost of Steam}}{\text{GJ (MMBtu)}}$$

the industry. The average cost of steam, instead of the marginal cost of the new steam, is used to reflect actual industrial cost accounting procedures of spreading the new steam costs over the entire product line.

The ratio of annual steam consumed (per unit output) to annual dollar value of shipment (per unit output) is computed by finding the quotient of annual steam consumption and the value of shipments. The ratio of annual steam consumed to annual dollar value of shipment by industry is assumed to remain constant over time. Ratios employed in this analysis are listed in Table 9-7.

Table 9-8 shows the amount of total steam potentially affected by a regulatory option. The amount of steam increases over time as new boilers come on-line and, potentially, are subject to the control level.

9.2.2.2 Economic Impacts.

9.2.2.2.1 Steam cost impacts. The cost of new steam, unlike the other components of the change in product price equation, is dependent upon the specific regulatory option chosen. The cost of new steam for 1985 and 1990 is projected by the Industrial Fuel Choice Analysis Model (IFCAM), an energy demand model developed by Energy and Environmental Analysis, Inc., IFCAM simulates fuel choice decisions for the industrial major steam users under different regulatory options.

The projected total annualized cost of new steam per GJ (MMBtu) is presented in Tables 9-9 and 9-10 for Regulatory Options I and V, by industry and year. These steam costs are functions of the boiler size and capacity utilization distribution of the individual industry, the region in which the industry is located, and the number of new boilers subject to the regulatory option.

There is a strong relationship between the boiler size/capacity utilization distribution of an industry and average steam cost per GJ (MMBtu) for an industry. Industries that operate predominantly small boilers of low capacity utilizations, such as the textiles and stone, clay, and glass industries, exhibit the highest cost per GJ (MMBtu). Lower steam costs are found in industries, such as paper and chemicals, firing larger boilers because they can capture economies of scale in steam production, allowing a lower steam cost per GJ (MMBtu).

TABLE 9-7. 1976 STEAM CONSUMPTION PER DOLLAR PRODUCT

SIC Code	Industry	Steam consumption per dollar product[a,b] 10^6 kJ per $ value of shipment	 10^6 Btu per $ value of shipment
20	Food	0.0037	0.0035
22	Textiles	0.0050	0.0047
26	Paper	0.0215	0.0204
28	Chemicals	0.0160	0.0152
29	Petroleum refineries	0.0044	0.0042
32	Stone, clay, and glass	0.0015	0.0014
3312, 3315-17	Steel	0.0063	0.0060
3334, 3353-55	Aluminum	0.0155	0.0147
	Other	0.0008	0.0008
	Total	0.0035	0.0033

[a] Energy and Environmental Analysis, Inc. The Industrial Sector Energy Consumption Data Base (ECDB) for 1975 and 1976. December 15, 1980.

[b] U.S. Department of Commerce, Bureau of the Census. Annual Survey of Manufactures. 1976.

TABLE 9-8. PERCENT OF NEW STEAM IN TOTAL STEAM CONSUMPTION[a]

Industry	1985	1990
Food	17	40
Textiles	5	21
Paper	8	26
Chemicals	19	40
Petroleum refineries	23	36
Stone, clay, and glass	0[b]	0[b]
Steel	9	26
Aluminum	13	41
Other	18	37
Total	16	36

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[a] Energy and Environmental Analysis, Inc. Industrial Fuel Choice Analysis Model. May 1980.

[b] The small amount of new steam demand in the stone, clay, and glass industry is projected to be met by boilers smaller than 15 MW (50 MMBtu/hr).

TABLE 9-9. NATIONWIDE AVERAGE ANNUALIZED COSTS FOR NEW INDUSTRIAL BOILERS BY INDUSTRY: 1985[a]
[1978 $/GJ (1978 $/MMBtu)]

Industry	Base Case[b]	Regulatory Option I[c]	Regulatory Option V[d]
Food	5.61 (5.92)	5.74 (6.06)	5.77 (6.09)
Textiles	5.77 (6.09)	6.01 (6.34)	6.14 (6.48)
Paper	5.02 (5.30)	5.13 (5.41)	5.17 (5.45)
Chemicals	4.92 (5.20)	5.06 (5.34)	5.07 (5.35)
Petroleum refining	4.98 (5.26)	5.15 (5.43)	5.27 (5.56)
Stone, clay, and glass	e	e	e
Steel	4.99 (5.27)	5.16 (5.44)	5.39 (5.69)
Aluminum	4.77 (5.04)	4.90 (5.17)	5.14 (5.42)
Other	5.18 (5.47)	5.35 (5.64)	5.46 (5.76)
Total	5.07 (5.35)	5.21 (5.50)	5.28 (5.57)

[a] IFCAM steam costs annualized over 15 years at a 10 percent discount rate, pre-tax.

[b] Base Case emission limits are in Table 9-4

[c] Regulatory Option I emission limits are in Table 9-5.

[d] Regulatory Option V emission limits are in Table 9-6.

[e] The small amount of new steam demand in the stone, clay, and glass industry is projected to be met by boilers smaller than 15 MW (50 MMBtu/hr).

TABLE 9-10. NATIONWIDE AVERAGE ANNUALIZED COSTS FOR NEW INDUSTRIAL BOILERS BY INDUSTRY: 1990[a]

[1978 $/GJ (1978 $/MMBtu)]

Industry	Base Case	Regulatory Option	
		I	V
Food	6.55(6.91)	6.68(7.05)	6.58(6.94)
Textiles	6.54(6.90)	6.74(7.11)	7.00(7.38)
Paper	5.54(5.84)	5.67(5.98)	5.72(6.03)
Chemicals	5.38(5.68)	5.56(5.87)	5.71(6.02)
Petroleum refining	5.62(5.93)	5.79(6.11)	5.91(6.23)
Stone, clay, and glass	e	e	e
Steel	5.70(6.01)	5.74(6.05)	6.08(6.41)
Aluminum	5.46(5.76)	5.57(5.88)	5.75(6.07)
Other	5.73(6.05)	5.93(6.25)	6.09(6.43)
Total	5.64(5.95)	5.80(6.12)	5.93(6.25)

[a] IFCAM steam costs annualized over 15 years at 10 percent discount rate, pre-tax.

[b] Base Case emission limits are in Table 9-4.

[c] Regulatory Option I emission limits are in Table 9-5.

[d] Regulatory Option V emission limits are in Table 9-6.

[e] All new steam demand in the stone, clay, and glass industry is projected to be met by boilers smaller than 15 MW (50 MMBtu/hr).

Rising fuel costs typically cause the total industry steam costs, displayed in Tables 9-9 and 9-10, to increase over time for both regulatory options.

The cost impact of the regulatory options on steam generation is more severe in Option V than in Option I due to the mandatory scrubbing requirement in Option V for smaller boilers.

9.2.2.2.2 Price impacts. The change in product price from the base case for the regulatory options for each industry assuming full cost pass-through is listed in Table 9-11. The change in product price is less than one percent for each of the major steam users. Option V generally results in the greatest price impact for all years. The percent change in product price for all industries increases over time, as more new steam capacity comes on-line and is subject to controls.

The greatest change in product price is found in those industries where steam is a large fraction of total product value, such as chemicals, paper, and aluminum.

The regulatory options examined do not affect product price significantly. As Table 9-11 shows, the product price increase is less than 1 percent for all industries and regulatory options examined. This result is due primarily to the relatively small fraction of total product value accounted for by steam.

The major steam users in aggregate will not experience a significant impact from the regulatory options. This does not mean, however, that a component of the major steam user industry group will not be affected adversely. The focus of the next section of this chapter is on selected industries both within the major steam users and from other manufacturing groups to assess whether smaller industry groups may be affected.

9.2.3 Selected Industries

The analysis of selected four-digit SIC industries forms the second part of the economic impact analysis. The economic analysis of selected industries focuses on cost impacts, capital availability, and profitability indicators.

The major steam users analysis in Section 9.2.2 considers industry averages in assessing economic impact. Since each two-digit SIC industry grouping is composed of many four-digit industries, the industry average may not capture the impact of regulatory options on each four-digit SIC industry. Also, the industry average may not reflect the impact on some four-digit SIC industries that are not considered in the major steam user analysis but that may be affected severely. Smaller four-digit SIC industries within a two-digit SIC industry may experience different pollution control costs and may vary in terms of financial indicators.

The industries chosen for this analysis were screened to identify four-digit SIC industries most likely to experience adverse economic impacts. These selected industries are:

- Beet sugar refining
- Fruit and vegetable canning
- Rubber reclaiming
- Automobile manufacturing
- Petroleum refining
- Iron and steel manufacturing
- Liquor distilling.

By evaluating the economic impact on industry groups most likely to be affected adversely, the impact on other industry groups can be inferred to be less severe.

The selected industry section (9.2.3) is organized into a summary of results (9.2.3.1) and description of methodology (9.2.3.2), followed by individual analyses of each of the seven selected industries (9.2.3.3 to 9.2.3.9).

9.2.3.1 Summary of Economic Impacts on Selected Industries. The economic impacts of the regulatory options on the seven selected industries are summarized in Table 9-12 for the base case, Regulatory Option I, and Regulatory Option V. Regulatory Option V represents the most stringent control level examined and, therefore, generates the maximum economic impacts. The change in product cost is 1 percent or less for all industries except beet sugar, which has a 3.9 percent increase under Regulatory Option V.

Return on assets does not vary significantly between the base case and Regulatory Options I and V for the selected industries except for liquor distilling and beet sugar refining. Return on assets for liquor distilling decreases from 1 percent in the base case to negative 0.5 percent under Regulatory Option V. Beet sugar changes from a positive 0.9 percent return

TABLE 9-11. CHANGE IN PRODUCT PRICE FROM THE BASE CASE
(percent)

	1985		1990	
	Regulatory Option		Regulatory Option	
Industry	I[a]	V[b]	I[a]	V[b]
Food	0.008	0.010	0.020	0.004
Textiles	0.006	0.009	0.021	0.027
Paper	0.018	0.024	0.074	0.101
Chemicals	0.040	0.043	0.116	0.207
Petroleum refining	0.016	0.029	0.027	0.045
Stone, clay, & glass	--	--	--	--
Steel	0.009	0.023	0.002	0.062
Aluminum	0.025	0.073	0.072	0.187
Other	0.002	0.004	0.006	0.011
Total	0.008	0.013	0.020	0.036

[a] Regulatory Option I emission limits are in Table 9-5.

[b] Regulatory Option V emission limits are in Table 9-6.

TABLE 9-12. SUMMARY OF CHANGE IN PRODUCT COST AND RETURN ON ASSETS FOR MODEL PLANTS IN SELECTED INDUSTRIES: 1990 (percent)

	Increase in product cost over base case		Return on assets		
	Regulatory Option			Regulatory Option	
	I[a]	V[b]	Base Case[c]	I[a]	V[b]
Beet sugar refining	0.40	3.90	0.86	0.56	(4.00)
Fruit & vegetable canning	0.05	0.05	2.32	2.32	2.32
Rubber reclaiming	0.10	0.60	4.09	3.58	1.02
Automobile manufacturing	0.00	0.02	8.10	8.09	8.04
Petroleum refining	0.08	0.08	5.94	5.92	5.92
Iron & steel manufacturing	0.01	0.07	3.37	3.36	3.32
Liquor distilling	0.24	0.64	1.26	0.68	0.50

[a] Regulatory Option I emission limits are in Table 9-5.

[b] Regulatory Option V emission limits are in Table 9-6.

[c] Base Case emission limits are in Table 9-4.

on assets under the base case to a negative 4.0 percent under Regulatory Option V.

The analysis of capital availability examines the ability of the model firm to finance the new boiler investment. The coverage ratios and debt/equity ratios were calculated for the base case, Regulatory Option I, and Regulatory Option V. The ratios did not vary significantly for any of the seven selected industries. If current financing schemes (i.e., split between debt and equity financing) for each industry are assumed to continue, the ratios are considered to be above "acceptable" levels under Regulatory Options I and V. This indicates that the industries should be able to absorb additional financing of new boiler investments without undue weakening of the solvency position of the industries.

9.2.3.2 Methodology.

9.2.3.2.1 Cost and profitability impacts. The following three steps are used to estimate the cost impact of regulatory options on a selected industry:

- Step One -- Define a model plant for the selected industry.
- Step Two -- Evaluate the cost impacts for the model plant, assuming full cost absorption.
- Step Three -- Evaluate the impacts on the profitability of the model plant.

Each step is described below.

Model plant. The selected industries analysis focuses on model plants to measure the economic impact of regulatory options on each industry. The model plant represents a typical plant for the segment of each industry that might be considering a boiler investment either as boiler expansion or replacement. A model plant is used since it is difficult to obtain precise details about the expansion and replacement plans of actual firms.

For this analysis, each plant within the firm is assumed to be identical in steam use and product output. Each plant employs the same process, produces equal amounts of output, operates identically configured boilers, and consumes equal amounts of steam. The fuel type burned in the existing boiler(s) of the model plant is determined by industry sources. The fuel type of the replacement or expansion boilers is based on industry trends and projections from IFCAM based on the combustor's size, location, and applicable energy and environmental regulations.

The following production characteristics for the model plant are supplied:

- Plant Output/Year -- average product output per year in those plants more likely to invest in new boilers.
- Price (Cost)/Unit of Output -- the historic, average selling price per unit, in real 1978 dollars.
- Plant Sales/Year -- plant output per year multiplied by price per unit of output.
- Plant Earnings/Year -- plant sales per year multiplied by a derived profit margin (percent return on sales). This figure estimates the profitability of the model plant.

Product cost calculation. The effect of regulatory options on product cost is calculated by finding the product of the change in the cost of new steam, the share of steam affected by the new regulation, and the amount of steam consumed per dollar of output. The cost impacts are stated in real terms. The only real cost increase is due to new boiler and fuel costs; all other real production costs are held constant.

Profitability impacts. The additional costs due to a regulatory option will affect the profitability of an industry. This impact will be assessed by examining the following two financial indicators for the model plant:

- Net Profit After Taxes (Net Income). Profit after all costs and taxes have been deducted.
- Return on Assets. Net income divided by total assets, converted to a percent form.

Both of these indicators are analyzed for the base case and for the impact cases (Regulatory Options I and V). The change in indicators due to regulatory options is a measure of the ability of the model plant to absorb the additional costs of a regulatory option.

Net income is calculated by subtracting expenses from total sales to derive gross profit and then taxes are subtracted from gross profit to equal net income. Regulatory options could affect the amount of expenses, which would alter net income. Return on assets is derived by dividing net income by total assets for the model plant and converting to a percent form. Alternative regulatory options could affect net income, resulting in a change in return on assets.

9.2.3.2.2 Capital availability. Capital availability constraints may result if regulatory options create a need for financing additional pollution control investments. The following two steps are used to evaluate whether capital availability will be a constraint on a selected industry:

- Step One -- Define financial indicators for a model firm.
- Step Two -- Evaluate the ability of a firm to finance pollution control investments.

The firm is the focus of the capital availability analysis because decisions involving large capital expenditures are made at the corporate level. Depending upon the state of corporate cash reserves and the relative costs of various financing tools, a firm will choose a combination of internal and external financing instruments to meet the additional investments required to comply with regulatory options.

The capital availability analysis focuses on the following two financial indicators, which measure each industry's financing ability:

- Coverage Ratio -- the number of times operating income (earnings before taxes and interest expenses) covers fixed obligations (annual interest on debt instruments and long-term leases).
- Debt/Equity Ratio -- a measure of the relative proportions of two types of external financing.

These two indicators are analyzed for both the base case and the regulatory options. The change in indicators due to regulatory options is analyzed to determine how difficult it will be for the firm to meet financial requirements for the pollution control equipment investment.

The cash flow coverage ratio is calculated by dividing operating income by fixed obligations, both of which could change as a result of alternative regulatory options. If the coverage ratio remains above the 3.0 standard benchmark, the cost of capital can be assumed to be above "acceptable" levels. However, as the coverage ratio falls, the cost of obtaining capital will rise.

The debt/equity ratio is calculated by dividing total debt by total equity of the firm (book values). The incremental debt incurred from financing the pollution control required by the regulatory options is added to the base case debt; the incremental equity issued to finance the remainder of the investment is added to the base case equity. A new debt/equity ratio then is calculated and the change is analyzed to assess the effect of the regulatory options on the firm's capital structure.

To determine the coverage and debt/equity ratios under alternative regulatory options, five financing strategies, which differ by the percentages of the investment financed by debt versus equity, are considered. (Note that for the changes in coverage ratios and debt/equity ratios, 100 percent external financing is assumed.) The external financing scenarios are:

- Zero percent new debt, 100 percent new equity
- 25 percent new debt, 75 percent new equity
- 50 percent new debt, 50 percent new equity
- 75 percent new debt, 25 percent new equity
- 100 percent new debt, zero percent new equity.

The financial indicators generated for this analysis were derived from a variety of published sources. Robert Morris Associates' Annual Statement Studies was consulted for composite industry financial data. More specific corporate figures were collected from Moody's Industrial Manuals and Form 10-K's and Annual Reports on file at the Securities and Exchange Commission.

9.2.3.3 Beet Sugar Refining Industry.

9.2.3.3.1 Model firm and plant description. The major characteristics of the model firm for the beet sugar refining industry are listed in Table 9-13. The model firm is made up of four plants, which are located in the north central United States (Federal Region 8). Each plant is identical in its steam use and product output.

Total annual firm production is 326,600 megagrams (360,000 tons) of sugar, with annual sugar sales at $126 million, assuming that sugar sells for $38.60 per hundred kilograms ($17.50 per hundred pounds) and that none of this sugar is added to existing inventories. Annual profits are 1.74 percent of total sales or about $2.2 million. Comparing these figures to the 1978 U.S. sugar demand, this firm satisfies slightly more than 3 percent of total demand and constitutes about 10 percent of the beet sugar market.

The model plant boiler house consists of four fossil fuel-fired boilers with a total heat input capacity of 132 MW (450 MMBtu/hr). Table 9-13 describes the individual boilers. The three new boilers are coal-fired units replacing similarly sized oil-fired boilers. Each new boiler has a

TABLE 9-13. MODEL FIRM AND PLANT CONFIGURATION: BEET SUGAR INDUSTRY

Model firm	
Financial data[a]	
Average bond rating:	Baa
Coverage ratio:	4.0
Debt/equity ratio:	0.41
Model plant	
Production data	
Plant output/year:	81,650 megagrams (90,000 tons)[b]
Price/unit output:	$38.60/hundred kilogram wt.[c] ($17.50/hundred pound wt.)
Plant sales/year:	$31.50 million[c]
Plant earnings/year:	$0.548 million[c, d]
Boiler configuration	
Total firing rate:	132.1 MW (450 MMBtu/hr)
No. of boilers:	4
Federal region:	8

Characteristics of individual boilers

	Boiler 1	Boiler 2	Boiler 3	Boiler 4
Capacity, MW (MMBtu/hr)	40.1 (137)	40.1 (137)	40.1 (137)	11.7 (40)
Fuel type	coal	coal	coal	residual fuel oil
Annual capacity utilization, percent	45	45	45	25
Replacement, expansion or existing	-----replacement-----			existing

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[a] Based upon 1978 values.

[b] Based upon the average production of the portion of the industry most likely to invest in a new boiler.

[c] Expressed in 1978 $.

[d] Based upon the 1977 return on sales ratio of 1.74 percent.

heat input capacity of 40 MW (137 MMBtu/hr) and an annual capacity utilization of 45 percent. Approximately 95 percent of total steam generated for the plant is from these new boilers. These three new boilers also are used for process heat and electricity generation.

9.2.3.3.2 Financial analysis. The financial analysis of the beet sugar industry shown in Table 9-15 focuses on 1974 to 1977. During this period, the industry's average annual net profits were positive, ranging from $4.2 million to $22 million. The period under consideration does not include 1978, since the negative profits realized in 1978 are considered atypical for the industry.

From 1974 to 1977, the industrial net profit margin ranged from 1.74 percent to 4.14 percent, averaging 3.4 percent. Return on total assets ranged from 2.27 to 11.71 percent. The beet sugar companies realized higher earnings during the post-sugar shortage years of 1975 and 1976.

According to industry sources, 1978 was an unprofitable -- and atypical -- year for the beet sugar industry due to low sugar prices. In that year, the industrial "average" net earnings* were negative; consequently, the industry's ratios (i.e., return on assets and net profit margin), all of which are a function of the industry's net earnings, were negative.

Capital availability is analyzed using debt/equity and coverage ratios. The model firm has a debt/equity ratio ranging from 0.25 to 0.41 for 1974 to 1977 and a coverage ratio ranging from 24.6, in post-sugar shortage 1976, to 2.10 in 1978.

9.2.3.3.3 Regulatory option results. In the base case, all the plant's boiler replacements are subject to SIP emission regulations. Industry representatives expect that any new boilers of this size will fire coal.[25] IFCAM also projects that coal is the least-cost fuel type and that a low sulfur western coal is the least-cost coal type. A Venturi scrubber will be installed to ensure that PM emissions do not exceed the level allowed by local regulations. In Regulatory Option I a Venturi scrubber is also chosen, while in Regulatory Option V, FGD controls are required.

Replacement boilers consist of three 40 MW (137 MMBtu/hr) units, operating at 45 percent annual capacity utilization. Table 9-15 shows the pre-tax 1990 boiler and pollution control costs for the regulatory options

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*Defined as the average of those firms most likely to invest in a new boiler, i.e., the six largest firms in the industry.

TABLE 9-14. FINANCIAL ANALYSIS: BEET SUGAR INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average, 1974-1978
Capital expenditures						
Total assets (10^6\$)	166.523	188.404	204.321	185.006	186.971	186.245
Capital expenditures/ firm (10^6\$)	9.493	13.411	16.963	10.720	8.153	11.748
Capital expenditures/ total assets (%)	5.7	7.1	8.3	5.8	4.4	6.3
Profitability						
Net profit after taxes (10^6\$)	14.21	22.07	13.82	4.20	(0.61)[b]	10.74
Return on assets (%)	8.53	11.71	6.76	2.27	(0.32)	5.77
Return on equity (%)	14.60	16.70	14.80	4.70	(0.70)	10.02
Return on sales (%)	4.14	4.00	3.57	1.74	(0.25)	2.64
Trends in dividends (\$ per share)	1.12	2.00	1.67	0.94	0.65	1.28
Net earnings before interest and taxes (10^6\$)	N.A.[c]	N.A.	26.39	17.09	9.58	17.69
Capitalization						
Interest on fixed obligations (10^6\$)	N.A.	N.A.	1.07	3.68	4.57	3.11
Coverage ratio	N.A.	N.A.	24.62	4.65	2.10	5.69
Rating on bonds	N.A.	N.A.	N.A.	Baa	N.A.	N.A.
Long-term debt (10^6\$)	36.37	29.99	28.32	34.38	35.74	32.96
Stockholders' equity (10^6\$)	89.27	101.94	115.13	89.23	87.27	96.57
Debt/capitalization (%)	28.95	22.73	19.74	[illegible].81	29.05	25.45
Debt/equity ratio	0.4074	0.2942	0.2460	0.3853	0.4095	0.3413

[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] Numbers in parentheses represent negative amounts.

[c] N.A. = Not Available.

TABLE 9-15. 1990 BOILER COSTS: BEET SUGAR MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978 $	20,650,000	20,880,000	23,475,750
Annualized total boiler cost, \$/GJ (\$/MMBtu)			
Capital	1.38 (1.46)	1.40 (1.48)	1.60 (1.69)
O&M	1.65 (1.74)	1.72 (1.81)	2.10 (2.22)
Fuel	1.07 (1.13)	1.07 (1.13)	1.21 (1.28)
Total	4.10 (4.33)	4.19 (4.42)	4.92 (5.19)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	718.00 (1.67)	718.00 (1.67)	374.00 (0.87)
Control Technology			
SO_2	----	----	Double Alkali/ Mechanical Collector
PM	Venturi Scrubber	Venturi Scrubber	----

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

applicable to the beet sugar industry. Boiler and pollution control capital costs for Regulatory Option I amount to $20.9 million, compared to the base case cost of $20.7 million. Total annualized boiler cost for the base case is $4.10 per GJ ($4.33 per MMBtu), compared to $4.19 per GJ ($4.42 per MMBtu) for Regulatory Option I. Total annualized cost of new steam for Regulatory Option V is $4.92 per GJ ($5.19 per MMBtu), a 19 percent increase over the base case.

Using the total steam cost figures, the cost of steam per dollar of output is calculated for the beet sugar industry. Table 9-16 illustrates the extent of product cost changes attributable to increased cost of new steam. Each kilogram (pound) of beet sugar produced requires approximately 19,500 kJ (8,378 Btu). Assuming that the cost of beet sugar equals its average selling price of $0.386 per kilogram ($0.175 per pound) and that new steam accounts for 95 percent of total steam use, the cost of new steam per dollar output ranges from $0.201 for Regulatory Option I to $0.2360 for Regulatory Option V. Resulting product cost changes range from 0.40 percent in Regulatory Option I to 3.90 percent in Regulatory Option V.

Table 9-17 presents the change in profitability levels as a result of increased cost of new steam. The analysis of the base case and the regulatory options assumes that sales are constant in real terms and that expenses increase only as a function of the new boiler investment. The incremental expense is assumed to be absorbed by the firm and is not passed on to the consumer. The resultant net income figures for the regulatory options range from $135,000 for Regulatory Option I to a net loss of $978,000 for Regulatory Option V, compared to a net income in the base case of $208,000. The adverse effect of the incremental costs associated with the new boiler investment is due in part to the low profitability level (0.66 percent of sales for the base case) existing in the industry. Return on assets for the regulatory options ranges from a positive 0.56 percent in Option I to a negative 4.0 percent in Option V. The negative return on assets suggests that the industry would choose not to replace the boiler, a decision which could result in a plant closure. The plant closure possibility for the beet sugar industry is the theoretical worst case that could develop. However, from a practical standpoint, closure may not occur due to a number of reasons.

First, the model firm for the beet sugar industry consists of four plants. The other three plants are not considering replacement and may be able to carry the loss burden resulting from the "impact" plant's replacement decision. Assuming a net income of $1.644 million for the three plants, a net loss of $978,000 from the impact plant would mean a decrease in the previous amount to $666,000. This is equivalent to a $222,000 profit per non-replacing plant, which translates to 0.7 percent return on sales from a previous level of 1.74 percent.

Second, based on a strict assumption that each plant is an independent cost center, and that other profitable plants cannot subsidize this loss, the conditions theoretically would warrant plant closure. However, viewing the firm as a profit entity composed of different profit-generating segments means that losses in certain segments may not necessarily dictate closure. Other factors must be considered, including how long the loss situation will be maintained, whether the magnitude of the loss offsets the other segments' earnings, how large the amount of sunk costs involved may be, and whether opportunity costs of not being able to supply buyers due to closure and/or loss of customers would affect the profitable segments' earnings.

Third, a net loss due to boiler replacement is attributable to increased expenses, i.e., variable costs. However, other significant fixed costs cannot be discounted. The cost savings that will be realized from the plant shutdown may be more than offset by the capital costs embedded in the plant. Plant closure may not be viable due to the existence of these fixed costs. Closure may occur only when the loss due to replacement is greater than the loss associated with the firm's inability to recover the fixed costs already in the existing plant.

Table 9-18 shows the effect of the regulatory options on coverage and debt/equity ratios in the beet sugar industry. Although there is little variation in coverage ratios as a function of regulatory options, there is a significant decrease when a higher debt level is assumed for the boiler investment. The biggest change occurs in Regulatory Option V, where coverage decreases from 4.0 in the zero percent debt level to 2.6 in the 100 percent debt level.

Debt/equity ratios increase significantly as a function of financing strategy. In Regulatory Option V, debt/equity increases from 0.32 to 0.68,

TABLE 9-16. CHANGE IN PRODUCT COST: BEET SUGAR MODEL PLANT

	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
GJ steam per kg (MMBtu/lb) output[d]	0.0195 (0.0084)	0.0195 (0.0084)	0.0195 (0.0084)
Percent of new steam per kg (lb) product[e]	95	95	95
Cost of new steam[f] per GJ (MMBtu), 1978 $	4.10 (4.33)	4.19 (4.42)	4.92 (5.19)
Cost of new steam per kg (lb) output, 1978 $	0.076 (0.034)	0.0776 (0.0352)	0.0743 (0.0413)
Average product cost per kg (lb), 1978 $	0.386 (0.175)	0.386 (0.175)	0.386 (0.175)
Cost of new steam per $ output, 1978 $	0.197	0.201	0.2360
Percent increase (decrease) in steam cost per $ output		2.04	19.80
Percent increase (decrease) in product cost		0.40	3.90

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[d] Estimated from industry contacts.

[e] Based on model plant configuration.

[f] Steam costs are 1990 pre-tax estimates.

TABLE 9-17. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: BEET SUGAR MODEL PLANT

	Base Case[a]		Regulatory Option I[b]		Regulatory Option V[c]	
	10^6 $	% of sales	10^6 $	% of sales	10^6 $	% of sales
Sales	31.500	100.00	31.500	100.00	31.500	100.00
Expenses	31.084	98.68	31.230	99.14	32.478	103.10
Gross profit	0.416	1.32	0.270	0.86	(0.978)	(3.10)
Taxes	0.208	0.66	0.135	0.43	0.0	0.0
Net income	0.208	0.66	0.135	0.43	(0.978)	(3.10)
Return on assets, %	0.86		0.56		(4.00)	

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[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-18. CAPITAL AVAILABILITY: BEET SUGAR MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	4.00	4.00	4.00
25	3.60	3.60	3.55
50	3.27	3.26	3.19
75	2.99	2.98	2.89
100	2.76	2.75	2.64
Debt/equity ratio			
Percent financed by debt			
0	0.34	0.33	0.32
25	0.40	0.40	0.40
50	0.47	0.47	0.48
75	0.55	0.56	0.57
100	0.65	0.65	0.68

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

compared to the base case increase of 0.34 to 0.65, for zero percent to 100 percent debt financing, respectively.

With regard to financing capability, the analysis of coverage ratios indicates that new boiler investment can be funded with debt ranging from 50 to 75 percent of total investment cost without going beneath the 3.0 standard benchmark. In terms of total capitalization, debt/equity ratios fall within the acceptable 1.0 benchmark. Assuming a 50 percent debt financing option (given that the 3.0 coverage benchmark is to be maintained), the debt ratio does not vary to a significant degree. This indicates a sufficient equity base to absorb additional financing of new boiler investment without undue weakening of the industry's financial position.

The profitability of the beet sugar industry in the base case is determined using industry sales data for 1977, a year in which the industry performed below average in terms of profitability. The financial impacts thus represent a worst case analysis in terms of the industry's ability to absorb the cost of replacing its steam plant. During other years in the mid-1970's, the beet sugar industry averaged a 3 to 4 percent return on sales, which is twice as high as depicted for the model firm. Thus, the typical firm actually may be able to make the new boiler investment without reducing its profit margin to near zero.

In addition, faced with increasing steam costs due to rising energy prices, the beet sugar firm likely would initiate energy conservation measures to reduce the level of steam use and overall production costs. This would result in an improved profit margin for the plant and more favorable conditions for investing in the new boilers.

The proposed standard is not expected to be the primary criterion in the decision to install a new steam plant. The firm will need to evaluate the investment as being cost-effective with or without more stringent emission regulations. Given the low rate of return in these firms, the major issue is whether any capital investment is justified, even with the intent of reducing energy costs by installing a coal-fired boiler. Under ARO I (essentially the proposed standards), the industry still would save energy costs by installing the coal-fired boiler, although savings would be less than in the base case.

9.2.3.4 Fruit and Vegetable Canning Industry.

9.2.3.4.1 Model firm and plant description. Table 9-19 depicts the firm and plant configuration of a typical fruit and vegetable canning operation. This analysis assumes that the model plant cans selected fruits and vegetables in proportions similar to the national average. This plant, located in Federal Region 9, is one of six canning plants that the typical firm operates.

The typical firm produces 21 million cases of processed fruits and vegetables each year and commands about 4 percent of the domestic canned goods market. The producer selling price per case is approximately $7.04 (1978 dollars), generating sales per firm of $147.8 million and earnings of $5.6 million.

The typical plant houses three fossil fuel-fired boilers that have a combined heat input capacity of 69 MW (236 MMBtu/hr). Each boiler operates at 25 percent of annual heat input capacity. The typical plant would replace the two larger boilers, listed on Table 9-19, with two natural gas-fired boilers of the same size.

9.2.3.4.2 Financial analysis. The financial indicators of the fruit and vegetable canning industry are depicted in Table 9-20. Historically, the industry's profits earned have been low but stable. Net profit margins (i.e., return on sales) have remained at a steady 3.6 percent, even during the 1974-1975 recession. Net profits ranged from $46.2 million to $70.1 million, with a 5-year average of $58.0 million. Return on assets averaged 8.3 percent over the 1977-1978 period.

The total amount of long-term capitalization and each of its components has increased over the years studied. Between 1977 and 1978, stockholders' equity increased by a greater percentage than did long-term debt: $465.0 million to $513.1 million (a 10 percent increase) compared with $152.7 million to $160.8 million (a 5 percent increase). The debt/equity ratio averaged 0.32 for 1977 and 1978. The coverage ratios of 10.99 for 1977 and 11.70 for 1978 indicate that, on average, operating income (earnings before interest and taxes) is more than adequate to support debt obligations.

9.2.3.4.3 Regulatory option results. The replacement boilers are expected to burn natural gas because of local environmental regulations.

Both of the regulatory options, but not the base case, have identical NO_x regulations that require combustion modification.

The difference in costs between the base case and regulatory options is due only to the cost of NO_x combustion modification. As Table 9-21 shows, the capital cost of the two new boilers varies from $2,335,000 for the base case to $2,428,000 for all others. The before-tax annualized components of total new steam cost (capital, O&M, and fuel) also are presented in the table. The total annualized steam cost is $7.19 per GJ ($7.59 per MMBtu) in the base case and $7.36 per GJ ($7.77 per MMBtu) in the regulatory options. The fuel cost of $5.12 per GJ ($5.40 per MMBtu) is a major component of the total cost in both options.

Table 9-22 lists the variables needed to calculate the cost of new steam per dollar product. Approximately 27,100 kJ (25,700 Btu) are needed to produce one case of canned goods. An average weighted price of $7.04 per case of output is assumed to be the 1978 producer price of canned fruits and vegetables. The cost of new steam represents approximately 2.05 percent of product cost in the base case and 2.10 percent in the regulatory cases. These calculations are based on the assumption that new steam accounts for 74 percent of total steam demand and that costs are fully absorbed by the producer.

Table 9-23 presents the change in profit margin due to a new boiler subject to a given regulatory option. Assuming a 50 percent corporate income tax and constant sales, net income is $260,000 in the base case. In Options I and V, net income declines $10,000 to $250,000.

The coverage ratio and the debt/equity ratio for the fruit and vegetable canning industry are shown in Table 9-24. These ratios do not vary between the base case and regulatory options due to the small capital cost difference between them. Both ratios appear to be in a healthy range, suggesting that the firm will be able to finance a new boiler investment.

The results of the analysis indicate that the regulatory options bring about little percentage change in product cost. New steam cost per dollar output is approximately 2.10 percent for both options. Profitability is affected only slightly by the environmental expenses of NO_x combustion modification required by the regulatory options.

TABLE 9-19. MODEL FIRM AND PLANT CONFIGURATION: FRUIT AND VEGETABLE CANNING INDUSTRY

Model firm

Financial data[a]

Average bond rating:	N.A.[b]
Coverage ratio:	11.7
Debt/equity ratio:	0.31

Model plant

Production data

Plant output/year:	3.5 million cases
Price/unit output:	$7.04 per case[c, d]
Plant sales/year:	$24.64 million[d, e]
Plant earnings/year:	$0.94 million[d, f]

Boiler configuration

Total firing rate:	69.2 MW (236 MMBtu/hr)
No. of boilers:	3
Federal region:	9

Characteristics of individual boilers

	Boiler		
	1	2	3
Capacity, MW (MMBtu/hr)	25.5 (87)	25.5 (87)	18.2 (62)
Fuel type	natural gas	natural gas	natural gas
Annual capacity utilization, percent	25	25	25
Replacement, expansion or existing	---replacement---	---replacement---	existing

---

[a] 1978 values.

[b] N.A. = Not available.

[c] Price/case of output is a weighted average (1974-1977) price of total canned fruits and vegetables produced, inflated to 1978 dollars.

[d] Expressed in 1978 $.

[e] Plant sales/year is derived by multiplying plant output/year by price/case of output.

[f] Based upon the 1978 return on sales ratio of 3.8 percent.

TABLE 9-20. FINANCIAL ANALYSIS: FRUIT AND VEGETABLE CANNING INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average, 1974-1978
Capital Expenditures						
Total assets (10^6 $)	N.A.[b]	N.A.	N.A.	749.6	834.8	792.2
Capital expenditures/ firm (10^6 $)	40.8	58.4	51.4	46.6	65.9	52.6
Capital expenditures/ total assets (%)	N.A.	N.A.	N.A.	6.2	7.9	7.1
Profitability						
Net profit after taxes (10^6 $)	46.2	54.7	57.0	61.6	70.1	57.95
Return on assets (%)	N.A.	N.A.	N.A.	8.2	8.4	8.3
Return on equity (%)	N.A.	N.A.	N.A.	13.2	13.7	13.5
Return on sales (%)	3.4	3.6	3.6	3.6	3.8	3.6
Trends in dividends ($ per share)	1.09	1.15	1.25	1.34	1.46	1.26
Net earnings before interest & taxes (10^6 $)	N.A.	N.A.	N.A.	190.2	210.4	200.3
Capitalization						
Interest on fixed obligations (10^6 $)	16.96	19.23	18.45	17.31	17.98	17.99
Coverage ratio	N.A.	N.A.	N.A.	10.99	11.70	11.35
Rating on bonds	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Long-term debt (10^6 $)	120.9	139.4	141.1	152.7	160.8	143.0
Stockholders' equity (10^6 $)	N.A.	N.A.	N.A.	465.0	513.1	489.1
Debt/capitalization (%)	N.A.	N.A.	N.A.	24.7	23.9	24.3
Debt/equity ratio	N.A.	N.A.	N.A.	0.3284	0.3134	0.3205

[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal Terms.

[b] N.A. = Not available.

TABLE 9-21. 1990 BOILER COSTS: FRUIT AND VEGETABLE CANNING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978$	2,334,760	2,427,760	2,427,760
Annualized total boiler costs, $/GJ ($/MMBtu)			
Capital	0.66 (0.70)	0.69 (0.73)	0.69 (0.73)
O&M	1.42 (1.50)	1.56 (1.65)	1.56 (1.65)
Fuel	5.12 (5.40)	5.12 (5.40)	5.12 (5.40)
Total	7.19 (7.59)	7.36 (7.77)	7.36 (7.77)
Control Technology			
NO_x	---	Combustion Modification	Combustion Modification

---

[a] The base case contains no regulations for these boilers.

[b] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

[c] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

TABLE 9-22. CHANGE IN PRODUCT COST: FRUIT AND VEGETABLE CANNING MODEL PLANT

		Regulatory Option	
	Base Case[a]	I[b]	V[c]
GJ (MMBtu) steam per case output[d]	0.0271 (0.0257)	0.0271 (0.0257)	0.0271 (0.0257)
Percent of new steam per case[e]	74	74	74
Cost of new steam[f] per GJ (MMBtu), 1978 $	7.19 (7.59)	7.36 (7.77)	7.36 (7.77)
Cost of new steam per case, 1978 $	0.1443	0.1478	0.1478
Average product cost per case, 1978 $	7.04	7.04	7.04
Cost of new steam per $ output, 1978 $	0.0205	0.0210	0.0210
Percent increase (decrease) in steam cost per $ output		2.44	2.44
Percent increase (decrease) in product cost		0.05	0.05

[a] The base case contains no regulations for these boilers.

[b] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

[c] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

[d] Estimated from industry contacts.

[e] Based on model plant configuration.

[f] Steam costs are 1990 pre-tax estimates.

TABLE 9-23. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: FRUIT AND VEGETABLE CANNING MODEL PLANT

	Base Case[a]		Regulatory Option I[b]		Regulatory Option V[c]	
	10^6\$	% of sales	10^6\$	% of sales	10^6\$	& of sales
Sales	24.64	100.00	24.64	100.00	24.64	100.00
Expenses	24.12	97.89	24.13	97.93	24.13	97.93
Gross profit	0.52	2.11	0.51	2.07	0.51	2.07
Taxes	0.26	1.06	0.25	1.01	0.25	1.01
Net income	0.26	1.06	0.26	1.06	0.26	1.06
Return on assets, %	2.32		2.32		2.32	

[a] The base case contains no regulations for these boilers.

[b] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

[c] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

TABLE 9-24. CAPITAL AVAILABILITY: FRUIT AND VEGETABLE CANNING MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	11.70	11.70	11.70
25	11.66	11.66	11.66
50	11.62	11.62	11.62
75	11.58	11.58	11.58
100	11.55	11.55	11.55
Debt/equity ratio			
Percent financed by debt			
0	0.31	0.31	0.31
25	0.31	0.31	0.31
50	0.32	0.32	0.32
75	0.32	0.32	0.32
100	0.32	0.32	0.32

[a] The base case contains no regulations for these boilers.

[b] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

[c] Regulatory Option I contains an 86 ng/J (0.2 lb/MMBtu) NO_x regulation for these boilers.

9.2.3.5 Rubber Reclaiming Industry.

9.2.3.5.1 Model firm and plant description. Table 9-25 presents the model plant and firm for the rubber reclaiming industry. Each plant within the industry is assumed to be identical in its production process; each produces the same amount of output with equal amounts of steam. The typical plant operates in the midwestern United States and has a yearly output of 18,100 megagrams (20,000 tons). The typical producer selling price is $0.37 per kilogram ($0.17 per pound), yielding sales of $6.7 million. Applying an industry-wide profit margin of 5.2 percent of sales, the model plant earns $350,000 in profit.

The typical plant's boiler house contains three boilers that have a combined firing capacity of 62 MW (211 MMBtu/hr). The replacement boiler is a coal-fired unit with a heat input capacity of 26 MW (87 MMBtu/hr). All boilers are assumed to operate at 45 percent of annual rated capacity.

9.2.3.5.2 Financial analysis. The financial parameters for the rubber reclaiming industry are listed in Table 9-26. The financial parameters for the rubber reclaiming industry are derived from data from the parts of the industry that are steam-intensive and whose reclaimed rubber sales comprise a substantial portion of total domestic corporate sales. It is assumed that the profit indicators for the entire corporation and the rubber reclaiming plant are comparable for a given year.

Although reclaimed rubber production has fluctuated from 1974 to 1978, corporate-wide profit margins (return on sales) have remained around 5 percent. Reclaimed rubber price increases have helped offset decreased sales, thus slightly increasing total sales revenue. Return on total assets has hovered around 8.8 percent for 1977 and 1978. Net profits have increased from $6.1 million per firm to $10.2 million from 1975 to 1978.

Uncertainty of product demand and resulting fluctuations in plant production have constrained new investment in production facilities. For this reason, investments in replacing capacity rather than extending plant capacity typify the industry. Although capitalization data exist only for 1977 to 1978, these financial indicators appear to be stable. Stockholders' equity per firm ranged from $86 million to $94 million. Long-term debt was between $23 million and $24 million for the 2-year period. The resulting debt/equity ratio hovered around the 2-year average of 0.26. This low long-term debt proportion suggests that the industry has unused debt capacity. Assuming that the firm will finance externally, the majority of the funds may come from debt instruments.

9.2.3.5.3 Regulatory option results. The new boiler under both regulatory options is projected to burn coal. IFCAM projects that coal is the least-cost fuel largely because of the high relative prices of residual oil and natural gas in this region. In the base case, in order to meet local PM emission regulations, and also under ARO I, the plant will install an electrostatic precipitator on the boiler.

Table 9-27 presents the pre-tax 1990 boiler and pollution control costs for the regulatory options for the typical boiler investment in the rubber reclaiming industry. Boiler and pollution control capital costs vary from $5,760,000 in the base case to $6,242,000 in Regulatory Option V. Annualized, these capital costs vary from $1.81 per GJ ($1.91 per MMBtu) for the base case to $2.03 per GJ ($2.14 per MMBtu) for Option V. Regulatory Option I requires an annualized capital cost of approximately $1.84 per GJ ($1.95 per MMBtu).

Table 9-27 also shows annual O&M and fuel costs which, combined with the capital costs, yield a total cost of new steam. Annual O&M costs vary from $2.05 per GJ ($2.16 per MMBtu) for the base case to $2.87 per GJ ($3.03 per MMBtu) in Option V. The annual O&M cost for Option I is $2.11 per GJ ($2.33 per MMBtu). Fuel costs are lowest in Option V because under this option the lowest cost compliance strategy is to scrub a higher sulfur coal. The total cost of new steam is highest in Option V at $6.94 per GJ ($7.32 per MMBtu), and the lowest for the base case at $6.28 per GJ ($6.63 per MMBtu), with Option I at $6.39 per GJ ($6.74 per MMBtu).

Using these total steam cost figures, the cost of new steam per dollar of output can be calculated for the rubber reclaiming industry. Table 9-28 depicts the calculation and presents results for the regulatory options. Each kilogram (pound) of reclaimed rubber produced requires approximately 10,500 kJ (4,513 Btu). Assuming that the cost of reclaimed rubber equals its real average selling price of $0.37 per kilogram ($0.17 per pound) and that new steam accounts for one-third of total steam use, the cost of new steam for the model plant ranges from 5.8 percent of the product cost in

TABLE 9-25. MODEL FIRM AND PLANT CONFIGURATION: RUBBER RECLAIMING INDUSTRY

Model firm	
Financial data[a]	
Average bond rating:	N.A.[b]
Coverage ratio:	9.9
Debt/equity ratio:	0.24
Model plant	
Production data	
Plant output/year:	18,100 megagrams (20,000 tons)[c]
Price/unit output:	$0.37/kilogram ($0.17/pound)[d]
Plant sales/year:	$6.7 million[d]
Plant earnings/year:	$0.35 million[d,e]
Boiler configuration	
Total firing rate:	61.8 MW (211 MMBtu/hr)
No. of boilers:	3
Federal region:	5

Characteristics of individual boilers

	Boiler		
	1	2	3
Capacity, MW (MMBtu/hr)	25.5 (87)	18.2 (62)	18.2 (62)
Fuel type	coal	oil/gas	oil/gas
Annual capacity utilization, percent	45	45	45
Replacement, expansion or existing	replacement	---existing----	

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[a] 1978 values.

[b] N.A. = Not available.

[c] Average of plant output/year for 1974 - 1978.

[d] Expressed in 1978 $.

[e] Based upon the 1978 return on sales ratio of 5.2 percent.

TABLE 9-26. FINANCIAL ANALYSIS: RUBBER RECLAIMING INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average 1974-1978
Capital expenditures						
Total assets (10^6\$)	N.A.[b]	N.A.	N.A.	108.1	116.6	112.4
Capital expenditures/ firm (10^6\$)	N.A.	N.A.	N.A.	11.5	7.5	9.5
Capital expenditures/ total assets (%)	N.A.	N.A.	N.A.	10.6	6.4	8.4
Profitability						
Net profit after taxes (10^6\$)	6.2	6.1	7.3	9.6	10.2	7.9
Return on assets (%)	N.A.	N.A.	N.A.	8.9	8.7	8.8
Return on equity (%)	N.A.	N.A.	N.A.	11.2	10.9	11.0
Return on sales (%)	4.8	4.9	4.9	5.4	5.2	5.1
Trends in dividends (\$ per share)	0.75	0.79	0.92	1.00	1.14	0.92
Net earnings before interest and taxes (10^6\$)	N.A.	N.A.	N.A.	23.9	26.7	25.3
Capitalization						
Interest on fixed obligations (10^6\$)	N.A.	N.A.	N.A.	2.3	2.7	2.5
Coverage ratio	N.A.	N.A.	N.A.	10.4	9.9	10.1
Rating on bonds	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Long-term debt (10^6\$)	N.A.	N.A.	N.A.	23.6	23.0	23.3
Stockholders' equity (10^6\$)	N.A.	N.A.	N.A.	85.5	93.9	89.7
Debt/capitalization (%)	N.A.	N.A.	N.A.	21.6	19.6	20.6
Debt/equity ratio	N.A.	N.A.	N.A.	0.2760	0.2444	0.2595

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[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] N.A. = Not available.

TABLE 9-27. 1990 BOILER COSTS: RUBBER RECLAIMING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs (1978 $)	5,760,000	5,820,000	6,241,610
Annualized total boiler costs, \$/GJ (\$/MMBtu)			
Capital	1.81 (1.91)	1.84 (1.95)	2.03 (2.14)
O&M	2.05 (2.16)	2.11 (2.23)	2.87 (3.03)
Fuel	2.43 (2.56)	2.43 (2.56)	2.04 (2.15)
Total	6.28 (6.63)	6.39 (6.74)	6.94 (7.32)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	744.00 (1.73)	744.00 (1.73)	997.00 (2.32)
Control Technology			
SO_2	---	---	Double Alkali/ Mechanical Collector
PM	Electrostatic Precipitator	Electrostatic Precipitator	---

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-28. CHANGE IN PRODUCT COST: RUBBER RECLAIMING MODEL PLANT

	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
GJ (MMBtu) steam per kg (lb) output[d]	0.010 (0.005)	0.010 (0.005)	0.010 (0.005)
Percent of new steam per kg (lb)[e]	33	33	33
Cost of new steam per GJ (MMBtu), 1978 $[f]	6.28 (6.63)	6.39 (6.74)	6.94 (7.32)
Cost of new steam per kg (lb), 1978 $	0.0218 (0.0099)	0.022 (0.010)	0.024 (0.011)
Average product cost per kg (lb), 1978 $	0.37 (0.17)	0.37 (0.17)	0.37 (0.17)
Cost of new steam per $ output, 1978 $	0.058	0.059	0.064
Percent increase (decrease) in steam cost per $ output		1.72	10.34
Percent increase (decrease) in product cost		0.10	0.60

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[d] Estimated from industry contacts.

[e] Based on model plant configurations.

[f] Steam costs are 1990 pre-tax estimates.

the base case to 6.4 percent in Option V. This calculation assumes that this cost increase is absorbed fully by the producer.

Table 9-29 presents the change in profit margin due to a new boiler investment. This table assumes that sales are constant in real terms and that expenses rise only due to the new boiler investment. Assuming a 50 percent corporate income tax, net income varies from $160,000 in the base case to 40,000 in Option V. Return on assets for the model plant varies from 4.09 percent for the base case to 3.58 percent in Option I and 1.02 percent in Option V.

Table 9-30 lists the rubber reclaiming industry's coverage ratio and debt/equity ratio for five financing options for the regulatory options. The coverage and debt/equity ratios do not vary significantly across regulatory options. These ratios do vary, however, depending on financing strategy. In Option V, for example, the coverage ratio decreases from 9.89 to 8.04 in the 100 percent debt financing option. While this represents a 19 percent decrease, the average ratio is still above the 3.0 standard benchmark. The debt/equity ratio for Option V varies from 0.23 to 0.31 for the five financing options, which is well below the 1.0 threshold level. The low long-term debt proportion suggests that the industry may have unused debt capacity. Assuming that the firm will finance externally, the majority of the external funds may come from debt instruments.

The results of the analysis indicate that the regulatory options cause percentage increases in product cost of 1 percent or less. Profits are positive in Option I and in Option V. Return on assets is 3.58 percent in Option I and 1.02 percent in Option V. Capitalization data suggest that the firm will be able to finance a new boiler investment under both regulatory options examined.

9.2.3.6 Automobile Manufacturing Industry.

9.2.3.6.1 Model firm and plant description. The model firm and plant configuration for the automobile manufacturing industry is presented in Table 9-31. The plant that operates in Federal Region 5 is assumed to be part of a 26-plant firm. Total firm production is 2,343,380 vehicles, with annual car and light truck sales of $14.64 billion, assuming an average price (1978 dollars) of $6,249 per vehicle. These production statistics do not include foreign-made cars (such as the Dodge Colt or the Ford Fiesta) normally part of United States automobile companies' fleets. Because these cars are not produced in this country, their production costs would not be affected by alternative regulatory options. Net profit for the model firm is assumed to be 4.28 percent on total sales of $626.7 million.

The model plant boiler house consists of four coal-fired boilers with a total heat input capacity of 102 MW (348 MMBtu/hr). The boiler investment decision is to replace one of these units with a similarly sized new coal-fired boiler.

9.2.3.6.2 Financial analysis. The financial indicators of the automobile manufacturing industry in 1974 and 1975, as shown in Table 9-32, reflect the apprehension of consumers to purchase new automobiles after the oil embargo of 1973-1974. Return on assets was approximately 3 percent, less than one-half of the 5-year average for 1974 to 1978. Return on sales reached a similar low of 2.09 percent compared to the 5-year average of 3.94 percent. By 1976, however, the industry had recovered. In fact, return on assets and return on sales surpassed the industry's 5-year average during the following 3 years. Note that net profit generally increased between 1974 to 1978, from $316 million to $1.2 billion.

Capital availability does not seem to pose problems for the typical automotive manufacturing plant. Long-term debt has remained relatively constant over the past 5 years, usually between $850 million and $950 million. Stockholders' equity, on the other hand, has increased from approximately $5.5 billion to $7.6 billion. This increase has caused the debt/equity ratio to fall from 0.16 to 0.11. Because these ratios show a low percentage of debt, future investments could be funded largely from debt, depending upon the interest rate and the industry's inclination toward debt financing.

The coverage ratio for the automobile manufacturing industry has been rising over the past 5 years from 10.52 to 20.17. The average 5-year coverage ratio of 16.68 is considered to be sufficiently high that the automobile manufacturing industry should not have difficulty obtaining debt financing.

TABLE 9-29. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: RUBBER RECLAIMING MODEL PLANT

	Base Case[a]		Regulatory Option I[b]		Regulatory Option V[c]	
	10^6\$	% of sales	10^6\$	% of sales	10^6\$	% of sales
Sales	6.70	100.00	6.70	100.00	6.70	100.00
Expenses	6.39	95.37	6.43	95.97	6.63	98.55
Gross profit	0.31	4.63	0.27	4.03	0.07	1.04
Taxes	0.15	2.39	0.13	2.01	0.03	0.53
Net income	0.16	2.39	0.14	2.01	0.04	0.53
Return on assets, %	4.09		3.58		1.02	

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-30. CAPITAL AVAILABILITY: RUBBER RECLAIMING MODEL FIRM

Financial Indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	9.89	9.89	9.89
25	9.40	9.37	9.34
50	8.93	8.93	8.87
75	8.53	8.50	8.42
100	8.14	8.14	8.04
Debt/equity ratio			
Percent financed by debt			
0	0.23	0.23	0.23
25	0.25	0.25	0.25
50	0.27	0.27	0.27
75	0.29	0.29	0.29
100	0.31	0.31	0.31

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-31. MODEL FIRM AND PLANT CONFIGURATION: AUTOMOBILE MANUFACTURING INDUSTRY

Model firm

Financial data[a]

Average bond rating:	Aaa/B
Coverage ratio:	20.17
Debt/equity ratio:	0.11

Model plant

Production data

Assembly plant output/year:	90,130 automobiles[b]
Price/unit output:	$6,249.00/automobile[c]
Assembly plant sales/year:	$563.22 million[c]
Assembly plant earning/year:	$24.11 million[c,d]

Boiler configuration

Total firing rate:	102.0 MW (348 MMBtu/hr)
No. of boilers:	4
Federal region:	5

Characteristics of individual boilers

	Boiler			
	1[e]	2	3	4
Capacity, MW (MMBtu/hr)	25.5 (87)	25.5 (87)	25.5 (87)	25.5 (87)
Fuel type	coal	coal	coal	coal
Annual capacity utilization, percent	0	25	25	25
Replacement, expansion or existing	-------existing-------			replacement

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[a] 1978 values.

[b] Based upon average industry estimates.

[c] Expressed in 1978 $.

[d] Based upon the 1978 return on sales ratio of 4.28 percent.

[e] Boiler number one is used as a standby boiler.

TABLE 9-32. FINANCIAL ANALYSIS: AUTOMOBILE MANUFACTURING INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average 1974-1978
Capital expenditures						
Total assets (10^6\$)	10,411	10,741	12,069	13,631	15,169	12,404.2
Capital expenditures/ firm (10^6\$)	1,142	916	957	1,545	1,955	1,303
Capital expenditures/ total assets (%)	10.97	8.53	7.93	11.33	12.89	10.50
Profitability						
Net profit after taxes (10^6\$)	316	335	1,042	1,285	1,232	842
Return on assets (%)	3.03	3.12	8.63	9.43	8.12	6.79
Return on equity (%)	5.79	6.04	16.93	18.72	16.14	13.30
Return on sales (%)	2.09	2.06	4.89	5.05	4.28	3.94
Trends in dividends (\$ per share)	1.89	1.12	2.02	2.69	2.59	2.06
Net earnings before interest and taxes (10^6\$)	1,452	1,730	3,039	3,557	3,732	2,702
Capitalization						
Interest on fixed obligations (10^6\$)	138	183	155	149	185	162
Coverage ratio	10.52	9.45	19.61	23.87	20.17	16.68
Rating on bonds	N.A.[b]	N.A.	N.A.	N.A.	Aaa/B	---
Long-term debt (10^6\$)	853	985	904	939	850	906.2
Stockholders' equity (10^6\$)	5,460	5,556	6,155	6,867	7,635	6,334.6
Debt/capitalization (%)	13.52	15.06	12.80	12.02	10.01	12.51
Debt/equity ratio	0.1563	0.1772	0.1468	0.1367	0.1113	0.1430

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[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] N.A. = Not Available.

9.2.3.6.3 Regulatory option results. In the base case, the plant's boiler replacement must comply with SIP air emission limits. Based on historical industry trends, the fuel for the new boiler is projected to be coal. IFCAM projects coal as the least-cost fuel available given the applicable SIPs. To meet the SIP specifications in the base case, the plant will install an electrostatic precipatator for PM control. Option I results in use of a compliance coal and a electrostatic precipatator. Flue gas desulfurization (FGD) and a single mechanical collector (MC) are used for SO_2 and PM control, respectively, in Option V.

Table 9-33 presents the pre-tax 1990 boiler and pollution control costs for the regulatory options for the automobile industry. Option V has significantly higher costs due to the mandatory FGD requirement. The capital cost in Option V is $5.86 million as compared to $5.85 million in the base case. The before-tax annualized components of total new steam cost also are presented in this table. The capital and O&M components vary significantly between Options I and V. Annualized capital costs are $3.36 per GJ ($3.54 per MMBtu) and O&M costs are $3.64 per GJ ($3.84 per MMBtu) in the base case. In Option V, the annualized capital costs are $3.43 per GJ ($3.62 per MMBtu) and O&M costs are $4.82 per GJ ($5.09 per MMBtu). Fuel costs are lowest in the base case and Option I, since higher sulfur coals are used.

Combining the above costs yields a total cost of new steam, which ranges from $9.03 per GJ ($9.53 per MMBtu) in the base case to $10.68 per GJ ($11.26 per MMBtu) in Option V.

The calculation of the cost of new steam per dollar output is depicted in Table 9-34. The calculation of profits assumes sales to be constant in real terms and expenses to rise only due to the new boiler investment. The additional costs are assumed to be fully absorbed by the firm. Typically, the industry consumes 1.735 GJ (1.645 MMBtu) for each new automobile produced. Assuming that the real price of a new car is $6,249 and that one-third of the steam consumed is new steam, the cost of new steam per car represents considerably less than one-tenth of 1 percent in both of the regulatory options.

Table 9-35 presents the change in profit margin calculations for the automotive industry. Because the boiler investment is such a small fraction of total expenses, the net income changes due to a regulatory option when compared to the base case are small. Option V results in a less than 1 percent decline in net income compared to the base case. Return on assets falls only slightly from 8.10 percent in the base case to 8.04 percent in Option V.

The coverage and debt/equity ratios for the automobile manufacturing industry are shown in Table 9-36. The coverage ratio declines slightly from 20.17 to 20.11 over the five financing options and shows little difference between regulatory options. The debt/equity ratio remains at around 0.11. Neither of these ratios suggests problems in obtaining capital in either of the regulatory options. Since these rates show a low percentage of debt, future investments could be funded largely from debt, depending upon the interest rate and the industry's inclination toward debt financing.

The results of the analysis indicate that the regulatory options do not significantly affect any of the above financial parameters. The impact on product cost is negligible due to the low ratio of new steam cost to total dollar output. Net income as a percent of sales is approximately 4.0 percent in all cases, with returns on assets of 8.0 percent for both regulatory options examined. Capital availability is not constrained by any of these cases, suggesting that the firm will be able to finance a new boiler replacement.

9.2.3.7 Petroleum Refining Industry.

9.2.3.7.1 Model firm and plant description. Table 9-37 presents the model firm and plant for the petroleum refining industry. This plant, operating in the Southwest (Federal Region 6), is assumed to be part of a seven-plant firm. Total production for the model firm is 112.93 million barrels of refined product per year. Assuming a real price of $33.65 per barrel and an annual net profit margin of 4.51 percent, the firm realizes annual sales of $3.8 billion and annual profits of $171.4 million. Comparing these figures to 1978 U.S. refined product consumption, this firm satisfies approximately 2 percent of total demand and accounts for about 4 percent of the domestically refined petroleum products market.

TABLE 9-33. 1990 BOILER COSTS: AUTOMOBILE MANUFACTURING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978 $	5,850,000	5,920,000	5,863,460
Annualized total boiler costs, $/GJ ($/MMBtu)			
Capital	3.36 (3.54)	3.39 (3.58)	3.43 (3.62)
O&M	3.64 (3.84)	3.75 (3.96)	4.82 (5.09)
Fuel	2.04 (2.15)	2.04 (2.15)	2.43 (2.56)
Total	9.03 (9.53)	9.18 (9.69)	10.68 (11.26)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	997.00 (2.32)	997.00 (2.32)	744.00 (1.73)
Control Technology			
SO_2	---	---	Double Alkali/ Mechanical Collector
PM	Electrostatic Precipitator	Electrostatic Precipitator	Double Alkali/ Mechanical Collector

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-34. CHANGE IN PRODUCT COST: AUTOMOBILE MANUFACTURING MODEL PLANT

	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
GJ (MMBtu) steam per unit output[d]	1.74 (1.65)	1.74 (1.65)	1.74 (1.65)
Percent of new steam per unit[e]	33.3	33.3	33.3
Cost of new steam per GJ (MMBtu), 1978 $[f]	9.03 (9.53)	9.18 (9.69)	10.68 (11.26)
Cost of new steam per unit output, 1978 $	5.22	5.30	6.17
Average product cost per unit output, 1978 $	6,249.	6,249.	6,249.
Cost of new steam per $ output, 1978 $	0.00084	0.00085	0.00099
Percent increase (decrease) in steam cost per $ output		1.19	17.51
Percent increase (decrease) in product cost		0.001	0.015

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[d] Estimated from industry contacts.

[e] Based on model plant configurations.

[f] Steam costs are 1990 pre-tax estimates.

TABLE 9-35. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: AUTOMOBILE MANUFACTURING MODEL PLANT

	Base Case[a]		Regulatory Option I[b]		Regulatory Option V[c]	
	10^6 \$	% of sales	10^6 \$	% of sales	10^6 \$	% of sales
Sales	563.22	100.00	563.22	100.00	563.22	100.00
Expenses	515.14	91.48	515.17	91.47	515.47	91.52
Gross profit	48.08	8.52	48.05	8.53	47.75	8.48
Taxes	24.04	4.26	24.02	4.27	23.87	4.24
Net income	24.04	4.26	24.03	4.27	23.88	4.24
Return on assets, %	8.10		8.09		8.04	

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-36. CAPITAL AVAILABILITY: AUTOMOBILE MANUFACTURING MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	20.17	20.17	20.17
25	20.16	20.16	20.16
50	20.14	20.14	20.14
75	20.13	20.13	20.13
100	20.11	20.11	20.11
Debt/equity ratio			
Percent financed by debt			
0	0.11	0.11	0.11
25	0.11	0.11	0.11
50	0.11	0.11	0.11
75	0.11	0.11	0.11
100	0.11	0.11	0.11

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-37. MODEL FIRM AND PLANT CONFIGURATION: PETROLEUM REFINING INDUSTRY

Model firm

Financial data[a]

Average bond rating:	Aaa/A
Coverage ratio:	14.12
Debt/equity ratio:	0.32

Model plant

Production data

Plant output/year:	16,133,000 barrels
Price/unit output:	$33.65 per barrel[b,c]
Plant sales/year:	$543.88 million[c]
Plant earnings/year:	$24.48 million[c,d]

Boiler configuration

Total firing rate:	381.0 MW(1300 MMBtu/hr)
No. of boilers:	4
Federal region:	6

Characteristics of individual boilers

	Boiler			
	1	2	3	4
Capacity, MW (MMBtu/hr)	95.2 (325)	95.2 (325)	95.2 (325)	95.2 (325)
Fuel type	refinery gas	refinery gas	natural gas	petroleum coke & residual oil
Annual capacity utilization, percent	75	75	75	75
Replacement, expansion, or existing	------existing--------			replacement

---

[a] 1978 values.

[b] The price per unit output is based upon the average price for all refined products.

[c] Expressed in 1978 $.

[d] Based upon the 1978 return on sales ratio of 4.51 percent.

The model plant boiler house consists of four boilers, with a total heat input capacity of 381 MW (1,300 MMBtu/hr). Each boiler has a firing capacity of 95 MW (325 MMBtu/hr) and is used at 75 percent of heat input capacity. Three of the boilers are existing units, firing refinery and natural gas. The fourth unit, firing a mixture of petroleum coke and residual oil, will be replaced by a new coal-firing boiler in 1990. Approximately 25 percent of boiler steam generation for this plant will be provided by the new coal-firing boiler.

9.2.3.7.2 Financial analysis. The petroleum refining industry historically has been able to recoup increased crude import costs and refinery costs through higher product prices charged to retail establishments. Since 1973, retail gasoline and fuel oil prices have kept pace with the nominal cost increases in crude imports. Federal price regulations create ceiling prices at the pump but have interfered minimally with the trend of higher retail fuel prices to maintain profit levels. The demand for refinery products has, in general, surpassed the supply capabilities of domestic refineries, causing price levels to rise in response to a tight market.

If the petroleum refining industry does face increased steam costs, it is not likely to adjust its production process to reduce the level of steam use in its production equipment. Steam is an integral input to most of the individual process elements in a refinery; thus, increased steam costs cannot be mitigated by process changes. Because steam is such an important input, new or replacement boiler investments are not likely to be cancelled due to an increase in steam costs. Product demand is healthy and sufficiently inelastic to cover these additional costs without having the refinery experience decreased profits.

Table 9-38 delineates the financial indicators of the petroleum refining industry. Because petroleum-derived products exhibited strong sales during 1974-1978, the profitability indicators for the industry have been high and stable. Profits were extremely healthy, especially in 1974, during the oil embargo. Since 1975, net profits ranged from $658 million to $868 million per year and averaged $775 million per firm between 1974 and 1978. Return on total assets was between 5.8 and 10.1 percent, with the 5-year average at 6.93 percent.

Capital availability appears to be stable for the petroleum refining industry. Although the coverage ratio has fallen in recent years, as of

TABLE 9-38. FINANCIAL ANALYSIS: PETROLEUM REFINING INDUSTRY[a]

Financial indicator	Year					Average 1974-1978
	1974	1975	1976	1977	1978	
Capital expenditures						
Total assets ($10^6\$$)	8,434.20	9,321.50	10,606.00	13,266.60	14,320.10	11,189.68
Capital expenditures/ firm ($10^6\$$)	1,153.10	1,302.00	1,371.10	1,271.30	1,400.20	1,299.54
Capital expenditures/ total assets (%)	13.67	13.97	12.90	9.58	9.78	11.61
Profitability						
Net profit after taxes ($10^6\$$)	855.0	657.8	733.80	762.50	867.70	775.36
Return on assets (%)	10.14	7.06	6.92	5.75	6.06	6.93
Return on equity (%)	18.07	12.91	13.22	12.77	13.45	13.95
Return on sales (%)	N.A.[b]	N.A.	N.A.	N.A.	4.51	N.A.
Trends in dividends ($ per share)	1.81	1.88	2.02	2.22	2.38	2.06
Net earnings before interest and taxes ($10^6\$$)	3,319.00	2,623.50	2,566.80	2,907.80	3,130.80	2,909.44
Capitalization						
Interest on fixed obligations ($10^6\$$)	108.70	130.90	156.70	188.10	221.80	161.24
Coverage ratio	30.53	20.04	16.38	15.46	14.12	18.04
Rating on bonds	Aaa/A	N.A.	N.A.	N.A.	N.A.	---
Long term debt ($10^6\$$)	1,276.30	1,578.60	1,979.20	2,131.80	2,049.70	1,803.12
Stockholders' equity ($10^6\$$)	4,732.40	5,094.30	5,552.00	5,970.00	6,449.00	5,559.54
Debt/capitalization (%)	21.24	23.66	26.28	26.31	24.12	24.49
Debt/equity ratio	0.2697	0.3099	0.3565	0.3571	0.3178	0.3243

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[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] N.A. = Not available.

1978 it was still, at 14.12, extremely high. This ratio is sufficiently high to assume that the refinery will not have problems in obtaining external funds for a boiler investment in the base case. Long-term debt has nearly doubled since 1974, from $1.3 billion to over $2 billion. This increase is counteracted partially by an increase in stockholders' equity from $4.7 billion to $6.4 billion. Consequently, the debt/equity ratio has increased only from 0.27 to 0.32.

9.2.3.7.3 Regulatory option results. Historically, a significant share of the boiler fossil fuel demand in the petroleum refining industry has been met with the use of liquid, solid, and gaseous waste by-products of refinery operations. Because the focus of this analysis is on the choice between coal, oil, and gas, the fuel type for the new boiler is limited to these fuels. IFCAM projects that the new boiler under both regulatory options will burn coal. The option cases require scrubbing and PM control.

Table 9-39 presents pre-tax 1990 boiler and pollution control costs under the regulatory options for the model petroleum refining plant. Costs are equal for Options I and V, as the cases have the same compliance strategies. The base case capital cost is $18.3 million, while the two options have capital costs of $19.3 million.

The annualized capital cost for the regulatory options is $1.00 per GJ ($1.05 per MMBtu), while the annualized base case capital cost is $0.95 per GJ ($1.00 per MMBtu). O&M costs vary from $1.43 per GJ ($1.51 per MMBtu) for the base case to approximately $1.72 per GJ ($1.81 per MMBtu) in Options I and V. Fuel costs range from $2.47 per GJ ($2.61 per MMBtu) in the base case to $2.27 per GJ ($2.39 per MMBtu) for Options I and V.

Combining the above components yields the total cost of new steam. Total cost is $4.84 per GJ ($5.11 per MMBtu) in the base case and $4.98 per GJ ($5.25 per MMBtu) in the two regulatory options.

The cost of new steam per dollar of output is shown in Table 9-40. Assuming that a barrel of refined output requires 196,440 kJ (186,200 Btu) of steam and that the cost per barrel of oil is $33.65, then the cost of new steam represents 0.7 percent of product costs in the regulatory options. This calculation assumes that new steam accounts for 24 percent of the total steam requirements and that the firm fully absorbs this cost increase.

TABLE 9-39. 1990 BOILER COSTS: PETROLEUM REFINING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978 $	18,335,450	19,335,990	19,335,990
Annualized total boiler costs, $/GJ ($/MMBtu)			
Capital	0.95 (1.00)	1.00 (1.05)	1.00 (1.05)
O&M	1.43 (1.51)	1.72 (1.81)	1.72 (1.81)
Fuel	2.47 (2.61)	2.27 (2.39)	2.27 (2.39)
Total	4.84 (5.11)	4.98 (5.25)	4.98 (5.25)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	374.03 (0.87)	2575.23 (5.99)	2575.23 (5.99)
Control Technology			
SO_2	---	Double Alkali	Double Alkali
PM	---	ESP	ESP

[a] Base case regulations for these boilers are 516 ng/J (1.2 lb/MMBtu) for SO_2; 43 ng/J (0.1 lb/MMBtu for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[b] Regulatory Option I regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

TABLE 9-40. CHANGE IN PRODUCT COST: PETROLEUM REFINING MODEL PLANT

	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
GJ (MMBtu) steam per bbl output[d]	0.19644 (0.18620)	0.19644 (0.18620)	0.19644 (0.18620)
Percent new steam per bbl[e]	24	24	24
Cost of new steam per GJ (MMBtu), 1978 $[f]	4.84 (5.11)	4.97 (5.25)	4.97 (5.25)
Cost of new steam per bbl, 1978 $	0.2284	0.2346	0.2346
Average product cost per bbl, 1978 $	33.65	33.65	33.65
Cost of new steam per $ output, 1978 $	0.0068	0.0070	0.0070
Percent increase (decrease) in steam cost per $ output		2.94	2.94
Percent increase (decrease) in product cost		0.0184	0.0184

[a] Base case regulations for these boilers are 516 ng/J (1.2 lb/MMBtu) for SO_2; 43 ng/J (0.1 lb/MMBtu for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[b] Regulatory Option I regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[d] Estimated from industry contacts.

[e] Based on model plant configuration.

[f] Steam costs are 1990 pre-tax estimates.

Table 9-41 presents the change in profit margin due to a new boiler investment. This calculation assumes that sales are constant in real terms and that expenses rise only due to the new boiler investment. Options I and V reduce base case net income by less than one percentage point. This small percentage change in product cost is due to the small fraction that new steam cost comprises of average product cost.

The coverage and debt/equity ratios for the model petroleum refinery for the regulatory options are presented in Table 9-42. As the table illustrates, neither the regulatory option nor the financing strategy affect these ratios significantly. The coverage ratio decreases approximately from 14.12 to 14.00, or less than 1 percent. The debt/equity ratio remains around 0.32 under all financing and control levels.

The results of the analysis indicate that neither of the regulatory options result in significant cost impacts on the petroleum refining industry. New steam costs for the regulatory options comprise a relatively small fraction of average product costs. Profitability is affected slightly by the incremental expenses due to new boiler investment. Return on assets, however, remains at 5.9 percent for both regulatory options.

Capital availability appears to be stable for the petroleum refining industry. The coverage ratio is sufficiently high to assume that the refinery will not have problems obtaining external funds for a boiler investment.

9.2.3.8 Iron and Steel Manufacturing Industry.

9.2.3.8.1 Model firm and plant description. Table 9-43 depicts the model firm and plant for the integrated iron and steel industry. This plant is assumed to be part of a five-plant firm, located in the midwestern States. Total production for the model firm is 8.2 million megagrams (9.0 million tons) of raw steel per year. Assuming a real price of $384 per megagram ($348 per ton) and an annual net profit margin of 2.9 percent, the firm realizes annual sales of $3.1 billion and annual profits of $90.9 million.

The model plant boiler house consists of four boilers with a total heat input capacity of 216 MW (736 MMBtu/hr). Three of the boilers have a capacity of 40 MW (137 MMBtu/hr) and the fourth has a capacity of 95 MW (325 MMBtu/hr). All the boilers currently fire blast furnace gas and have an annual capacity utilization of 55 percent. The three 40 MW boilers will be replaced by three similarly sized coal-fired boilers. Approximately 55 percent of boiler steam generation for this plant will be provided by the new coal-fired boilers.

9.2.3.8.2 Financial analysis. The major financial indicators of the average firm in the iron and steel industry are shown in Table 9-44. A record level for profits was set in 1974, followed by declining profits in 1975 and 1976, and a net loss in 1977. Profits increased in 1978, but did not approach the previous level of 1974.

Net profit declined from $259.6 million in 1974 to $143.2 million in 1976, followed by a net loss of $7.8 million in 1977. However, 1978 witnessed a return to pre-1977 profit levels, with a net profit of $155.3 million. Long-term debt has increased steadily from $666.8 million in 1975 to $1.03 billion in 1978. Debt levels for 1977 to 1978 have remained at slightly over one-third of total capitalization.

9.2.3.8.3 Regulatory option results. The three replacement boilers for the iron and steel manufacturing industry are assumed to burn coal. In order to meet local emission regulations in the base case and to meet ARO I, a fabric filter is installed for PM control. A compliance coal for SO_2 is chosen in the base case and Option I, while scrubbing is required in Option V with the selection of a FGD/single mechanical collector for SO_2 and PM control. Table 9-45 shows pre-tax 1990 boiler and pollution control costs for the regulatory options applicable to the iron and steel industry. Boiler and pollution control capital costs range from $20.3 million in the base case to $22.6 million in Option V.

Annualized capital cost in the base case is $1.11 per GJ ($1.17 per MMBtu) compared to $1.27 per GJ ($1.34 per MMBtu) in Option V. O&M costs of $2.05 per GJ ($2.16 per MMBtu) are also higher in Option V, while fuel costs are lower. Fuel costs are lower since a high sulfur coal, requiring scrubbing, is burned. Total cost of producing new steam is highest in Option V at $5.36 per GJ ($5.66 per MMBtu), compared to $5.10 per GJ ($5.38 per MMBtu) in the base case.

As shown in Table 9-46, each megagram (ton) of iron and steel produced requires approximately 1.705 GJ (1.465 MMBtu). Assuming that the cost of

TABLE 9-41. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: PETROLEUM REFINING MODEL PLANT

	Base Case[a]		Regulatory Option			
			I[b]		V[c]	
	10^6 $	% of sales	10^6 $	% of sales	10^6 $	% of sales
Sales	542.88	100.00	542.88	100.00	542.88	100.00
Expenses	494.93	91.12	495.02	91.55	495.02	91.55
Gross profit	47.95	8.83	47.86	8.82	47.86	8.82
Taxes	23.97	4.42	23.93	4.41	23.93	4.41
Net income	23.98	4.42	23.93	4.41	23.93	4.41
Return on assets, %	5.94		5.92		5.92	

[a] Base case regulations for these boilers are 516 ng/J (1.2 lb/MMBtu) for SO_2; 43 ng/J (0.1 lb/MMBtu for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[b] Regulatory Option I regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

TABLE 9-42. CAPITAL AVAILABILITY: PETROLEUM REFINING MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	14.12	14.12	14.12
25	14.09	14.08	14.08
50	14.06	14.05	14.05
75	14.03	14.02	14.02
100	14.00	13.99	13.99
Debt/equity ratio			
Percent financed by debt			
0	0.32	0.32	0.32
25	0.32	0.32	0.32
50	0.32	0.32	0.32
75	0.32	0.32	0.32
100	0.32	0.32	0.32

[a] Base case regulations for these boilers are 516 ng/J (1.2 lb/MMBtu) for SO_2; 43 ng/J (0.1 lb/MMBtu for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[b] Regulatory Option I regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 430 ng/J (1.0 lb/MMBtu) and 90-50% reduction for SO_2; 22 ng/J (0.05 lb/MMBtu) for PM; and 301 ng/J (0.7 lb/MMBtu) for NO_x.

TABLE 9-43. MODEL FIRM AND PLANT CONFIGURATION: IRON AND STEEL MANUFACTURING INDUSTRY

Model firm	
Financial data[a]	
Average bond rating:	N.A.[b]
Coverage ratio:	6.09
Debt/equity ratio:	0.52
Model plant	
Production data	
Plant output/year:	1,632,600 megagrams (1,800,000 tons)
Price/unit output:	$384 per megagram ($348 per ton)[c]
Plant sales/year:	$626.4 million[c]
Plant earnings/year:	$18.2 million[c,d]
Boiler configuration	
Total firing rate:	215.6 MW (736 MMBtu/hr)
No. of boilers	4
Federal region:	5

Characteristics of individual boilers	Boiler			
	1	2	3	4
Capacity, MW (MMBtu/hr)	40.1 (137)	40.1 (137)	40.1 (137)	95.2 (325)
Fuel type	coal	coal	coal	blast furnace gas
Annual capacity utilization, percent	55	55	55	55
Replacement, expansion or existing	---replacement----			existing

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[a] 1978 values.

[b] N.A. = Not available.

[c] Expressed in 1978 $.

[d] Based on the 1978 return on sales ratio of 2.9 percent.

TABLE 9-44. FINANCIAL ANALYSIS: IRON AND STEEL MANUFACTURING INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average 1974-1978
Capital expenditures						
Total assets (10^6 $)	N.A.[b]	N.A.	N.A.	N.A.	4,370.1	N.A.
Capital expenditures/ firm (10^6 $)	234.9	373.2	367.6	322.1	275.4	314.7
Capital expenditures/ total assets (%)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Profitability						
Net profit after taxes (10^6 $)	259.6	166.1	143.2	(7.8)	155.3	143.3
Return on assets (%)	N.A.	N.A.	N.A.	N.A.	3.55	N.A.
Return on equity (%)	15.2	9.2	7.5	(0.4)	7.9	7.9
Return on sales (%)	6.5	4.7	3.7	(0.2)	2.9	3.5
Trends in dividends ($ per share)	2.37	2.12	2.07	1.94	1.90	2.08
Net earnings before interest and taxes (10^6 $)	626.3	393.4	360.8	173.8	489.7	408.4
Capitalization						
Interest on fixed obligations (10^6 $)	35.6	39.9	52.9	75.3	80.4	56.8
Coverage ratio	17.59	9.86	6.82	2.31	6.09	8.53
Rating on bonds	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Long-term debt (10^6 $)	533.2	666.8	799.5	998.8	1,029.9	805.6
Stockholders' equity (10^6 $)	1,703.9	1,801.6	1,903.9	1,847.0	1,967.7	1,844.8
Debt/capitalization (%)	23.83	27.01	29.58	35.10	34.36	29.98
Debt/equity ratio	0.3129	0.3701	0.4199	0.5408	0.5234	0.4334

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[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] N.A. = Not available.

TABLE 9-45. 1990 BOILER COSTS: IRON AND STEEL MANUFACTURING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978 $	20,260,000	20,490,000	22,610,790
Annualized total boiler cost, \$/GJ (\$/MMBtu)			
Capital	1.11 (1.17)	1.24 (1.18)	1.27 (1.34)
O&M	1.64 (1.73)	1.67 (1.76)	2.05 (2.16)
Fuel	2.35 (2.48)	2.35 (2.48)	2.04 (2.15)
Total	5.10 (5.38)	5.14 (5.42)	5.36 (5.66)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	739.00 (1.72)	739.00 (1.72)	997.00 (2.32)
Control technology			
SO_2	---	---	Double Alkali/ Mechanical Collector
PM	Fabric Filter	Fabric Filter	---

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[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-46. CHANGE IN PRODUCT COST: IRON AND STEEL MANUFACTURING MODEL PLANT

		Regulatory Option	
	Base Case[a]	I[b]	V[c]
GJ steam per Mg (MMBtu/ton) output[d]	1.705 (1.465)	1.705 (1.465)	1.705 (1.465)
Percent of new steam per Mg (ton) output[e]	55	55	55
Cost of new steam per GJ (MMBtu), 1978 $[f]	5.10 (5.38)	5.14 (5.42)	5.36 (5.66)
Cost of new steam per Mg (ton) output, 1978 $	4.78 (4.33)	4.82 (4.37)	5.03 (4.56)
Average product cost per Mg (ton), 1978 $	384.00 (348.00)	384.00 (348.00)	384.00 (348.00)
Cost of new steam per $ output, 1978 $	0.0124	0.0125	0.0131
Percent increase (decrease) in steam cost per $ output		0.81	5.69
Percent increase (decrease) in product cost		0.01	0.07

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[d] Estimated from industry contacts.

[e] Based on model plant configuration.

[f] Steam costs are 1990 pre-tax estimates.

iron and steel equals its real average selling price of $384 per megagram ($348 per ton) and that new steam accounts for 55 percent of total steam use, cost of new steam per dollar output ranges from 0.0124 for the base case to 0.0131 for Option V. For Option V, product cost increases by one-tenth of a percent. The narrow variation and relatively low cost of new steam per output for the regulatory options compared to average product cost accounts for the small range in product cost changes.

Table 9-47 indicates that there is no significant change in profitability levels for the industry as a result of the changes in cost of new steam. The analysis for the base case and regulatory options assumes that sales are held constant in real terms and that expenses increase only as a result of new boiler investment. This incremental expense is assumed to be absorbed by the firm and is not passed on to the consumer. Given this assumption, net income is $17.24 million in Option I and $17.00 million in Option V, compared to $17.28 million for the base case. Return on assets ranges from 3.36 percent in Option I to 3.32 percent in Option V. Because of the relatively large sales and expense base for the industry, the incremental expense brought about by the increase in new steam cost of the regulatory option does not significantly affect overall profitability.

Table 9-48 shows that coverage and debt/equity ratios do not vary significantly as a function of regulatory options. However, there is a slight change in coverage as a function of debt financing strategy. The coverage ratio decreases from approximately 6.09 with zero percent debt financing to approximately 5.94 with 100 percent debt in both the base case and Option I and to 5.92 in Option II. The debt/equity ratios vary from 0.52 to 0.53 for the various financing strategies.

The results of the analysis indicate that the regulatory options cause low percentage increases in product cost. New steam costs for the regulatory options comprise a relatively small portion of average product cost. Profitability likewise is affected slightly by the incremental expenses due to new boiler investment. Although slight differences in net income exist between the regulatory options and the base case, return on sales remains at approximately 2.7 percent.

With regard to financing capability, the analysis of coverage ratios indicates that new boiler investment can be funded with up to 100 percent debt. The 3.0 coverage benchmark is always exceeded even when total debt financing is assumed. This firm's solvency position remains stable even when total debt financing is undertaken. Due to the industry's large equity base, the debt ratios do not exhibit wide variances as a result of the five financing options.

9.2.3.9 Liquor Distilling Industry.

9.2.3.9.1 Model firm and plant description. The model plant and boiler configuration of the liquor distilling industry is shown in Table 9-49. It is assumed that the typical firm operates three plants. The model plant is located in a southeastern State and produces 17 million liters (4.5 million gallons) of distilled liquor annually.

The model plant operates two boilers, one rated at 25 MW (87 MMBtu/hr), the other at 18 MW (62 MMBtu/hr), with a total firing capacity of 44 MW (149 MMBtu/hr) and 45 percent capacity utilization. The model plant elects to replace the two older natural gas/oil-fired boilers with identically configured coal-fired boilers.

9.2.3.9.2 Financial analysis. The domestic liquor distilling industry appears to have performed moderately well between 1976 and 1978, based on the financial indicators shown in Table 9-50. Although certain segments of the industry have outperformed others, overall profits have grown steadily.

Between 1976 and 1978, net profits before interest and taxes almost doubled over the same time period -- from $10.83 million in 1976 to $18.36 million in 1978. Relative profitability indicators increased between 1976 and 1978 as well: return on total assets grew from 2.1 percent to 3.9 percent, while return on sales improved from 2.4 percent to 4.3 percent.

Between 1976 and 1978, total assets increased at an annual rate of nearly 7 percent. In 1976, total assets per firm averaged $136.87 million; by the end of 1978, average assets reached $155.38 million.

Long-term debt obligations fluctuated within the $21 to $27 million range, comprising about one-fifth of total capitalization. Coverage of fixed obligations has continually improved from 1976 to 1978. The debt/equity ratio ranged from 0.24 to 0.31 during this period.

9.2.3.9.3 Regulatory option results. The model plant replacement boilers for the liquor distilling industry are assumed to be coal-fired. To meet SIP emission regulations in the base case, a single mechanical collector is installed for PM control. An electrostatic precipatator will

TABLE 9-47. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: IRON AND STEEL MANUFACTURING MODEL PLANT

	Base Case[a]		Regulatory Options			
			I[b]		V[c]	
	10^6\$	% of sales	10^6\$	% of sales	10^6\$	% of sales
Sales	626.40	100.00	626.40	100.00	626.40	100.00
Expenses	591.84	94.48	591.92	94.50	592.40	94.57
Gross profit	34.56	5.52	34.48	5.50	34.00	5.43
Taxes	17.28	2.76	17.24	2.75	17.00	2.71
Net income	17.28	2.76	17.24	2.75	17.00	2.71
Return on assets, %	3.37		3.36		3.32	

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-48. CAPITAL AVAILABILITY: IRON AND STEEL MANUFACTURING MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	6.09	6.09	6.09
25	6.05	6.05	6.05
50	6.02	6.01	6.01
75	5.98	5.98	5.96
100	5.94	5.94	5.92
Debt/equity ratio			
Percent financed by debt			
0	0.52	0.52	0.52
25	0.52	0.52	0.52
50	0.53	0.53	0.53
75	0.53	0.53	0.53
100	0.53	0.53	0.53

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-49. MODEL FIRM AND PLANT CONFIGURATION: LIQUOR DISTILLING INDUSTRY

Model firm

Financial data[a]

Average bond rating: N.A.[b]
Coverage ratio: 5.44
Debt/equity ratio: 0.292

Model plant

Production data

Plant output/year: 17.0 million liters (4.5 million gallons)
Price/unit output: $1.66/liter ($6.27/gallon)[c]
Plant sales/year: $28.22 million[c]
Plant earnings/year: $1.21 million[c,d]

Boiler configuration

Total firing rate: 43.7 MW (149 MMBtu/hr)
No. of boilers: 2
Federal region: 4

Characteristics of individual boilers

	Boiler	
	1	2
Capacity, MW (MMBtu/hr)	25.5 (87)	18.2 (62)
Fuel type	coal	coal
Annual capacity utilization, percent	45	45
Replacement, expansion, or existing	-replacement-	

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[a] 1978 values.

[b] N.A. = Not Available.

[c] Expressed in 1978 $.

[d] Based upon the 1978 return on sales ratio of 4.3 percent.

TABLE 9-50. FINANCIAL ANALYSIS: LIQUOR DISTILLING INDUSTRY[a]

Financial indicator	Year 1974	1975	1976	1977	1978	Average 1974-1978
Capital expenditures						
Total assets (10^6 $)	N.A.[b]	N.A.	136.87	146.89	155.38	146.4
Capital expenditures/firm (10^6 $)[a]	3.25	2.58	2.32	4.85	N.A.	3.25
Capital expenditures/ total assets (%)	N.A.	N.A.	1.70	3.30	N.A.	2.50
Profitability						
Net profit after taxes (10^6 $)[a]	N.A.	N.A.	2.8	5.0	6.1	4.6
Return on total assets (%)	N.A.	N.A.	2.1	3.4	3.9	3.1
Return on equity (%)	N.A.	N.A.	3.3	5.7	6.7	5.2
Return on sales (%)	N.A.	N.A.	2.4	4.0	4.3	3.6
Trends in dividends ($ per share)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Net earnings before interest and taxes (10^6 $)	N.A.	N.A.	10.83	14.35	18.36	14.5
Capitalization						
Interest on fixed obligations (10^6 $)	N.A.	N.A.	3.22	3.06	3.37	3.22
Coverage ratio	N.A.	N.A.	3.36	4.69	5.44	4.50
Rating on bonds	N.A.	N.A.	N.A.	N.A.	Ba	N.A.
Long-term debt (10^6 $)	N.A.	N.A.	26.42	20.65	26.57	24.55
Stockholders' equity (10^6 $)	N.A.	N.A.	85.29	87.62	91.08	88.0
Debt/capitalization (%)	N.A.	N.A.	0.236	0.191	0.226	0.218
Debt/equity ratio	N.A.	N.A.	0.310	0.236	0.292	0.279

[a] Average per firm estimates (Securities and Exchange Commission; EEA estimates). Nominal terms.

[b] N.A. = Not available.

be used in Option I. An SO_2 compliance coal is chosen in the base case and Option I, while scrubbing is required in Option V.

Table 9-51 shows pre-tax 1990 boiler and pollution control costs for the regulatory option applicable to the liquor distilling industry. Boiler and pollution control capital costs for the typical boiler investment in the industry range from about \$6.9 million in the base case to \$9.0 million in Option V. Annualized capital cost in the base case is \$1.26 per GJ (\$1.33 per MMBtu) compared to \$1.72 per GJ (\$1.81 per MMBtu) in Option V.

Replacements consist of two boilers, one rated at 25 MW (87 MMBtu/hr) and the other at 18 MW (62 MMBtu/hr), each with a 45 percent annual capacity utilization. Annualized costs are weighted with the corresponding boiler sizes to determine an average total cost of new steam.

Total cost of steam is highest in Option V at \$6.85 per GJ (\$7.23 per MMBtu), compared to the base case level of \$5.38 per GJ (\$5.68 per MMBtu). The difference in total cost of new steam between these two levels, however, is primarily due to capital and O&M cost differentials. Option V exhibits an annualized cost of \$2.95 per GJ (\$3.11 per MMBtu) compared to \$1.95 per GJ (\$2.06 per MMBtu) in the base case. Annualized fuel cost varies slightly between \$2.17 per GJ (\$2.29 per MMBtu) in the base case and \$2.19 per MMBtu (\$2.31 per MMBtu) in Option V.

On the basis of these total steam costs, the resultant cost of new steam per dollar of output for the industry can be calculated, as shown in Table 9-52. The steam requirement per liter output is 0.00725 GJ (0.026 MMBtu per gallon). Given an average cost of \$1.66 per liter (\$6.27 per gallon) of output, the increase in product cost for Option V represents a 0.64 percent increase over the base case level. Option I exhibits an increase in product cost of 0.24 percent.

Table 9-53 illustrates the changes in profitability levels due to the new boiler investment. Sales are assumed to be constant in both regulatory options and expenses increase only as a result of the new boiler investment. The incremental expense is assumed to be absorbed by the firm and is not passed on to the consumer. After-tax returns on sales of 1.37 percent in the base case declines to 0.74 percent in Option I, and becomes negative 0.46 percent in Option V. Net income levels for the regulatory options range from \$210,000 in Option I to a net loss of \$140,000 in Option V.

TABLE 9-51. 1990 BOILER COSTS: LIQUOR DISTILLING MODEL PLANT

Costs	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Total boiler and pollution control capital costs, 1978 $	6,850,000	8,500,000	9,000,770
Annualized total boiler cost, \$/GJ (\$/MMBtu)			
Capital	1.26 (1.33)	1.57 (1.66)	1.72 (1.81)
O&M	1.95 (2.06)	2.21 (2.33)	2.95 (3.11)
Fuel	2.17 (2.29)	2.17 (2.29)	2.19 (2.31)
Total	5.38 (5.68)	5.95 (6.28)	6.85 (7.23)
Coal type, ng SO_2/J (lb SO_2/MMBtu)	743.00 (1.73)	743.00 (1.73)	529.00 (1.23)
Control technology			
SO_2	---	---	Double Alkali/ Mechanical Collector
PM	Single Mechanical Collector	Electrostatic Precipitator	---

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

TABLE 9-52. CHANGE IN PRODUCT COST: LIQUOR DISTILLING MODEL PLANT

		Regulatory Option	
	Base Case[a]	I[b]	V[c]
GJ steam per liter (MMBtu/gallon) output[d]	0.00725 (0.02600)	0.00725 (0.02600)	0.00725 (0.02600)
Percent of new steam per liter (gallon) output[e]	100	100	100
Cost of new steam per GJ (MMBtu), 1978 $[f]	5.38 (5.68)	5.95 (6.28)	6.85 (7.23)
Cost of new steam per liter (gallon) output, 1978 $	0.0390 (0.1477)	0.0431 (0.1633)	0.0497 (0.1880)
Average product cost per liter (gallon), 1978 $	1.66 (6.27)	1.66 (6.27)	1.66 (6.27)
Cost of new steam per $ output, 1978 $	0.0236	0.0260	0.0300
Percent increase (decrease) in steam cost per $ output		10.35	27.12
Percent increase (decrease) in product cost		0.244	0.640

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[d] Estimated from industry contracts.

[e] Based on model plant configuration.

[f] Steam costs are 1990 pre-tax estimates.

TABLE 9-53. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT: LIQUOR DISTILLING MODEL PLANT

	Base Case[a]		Regulatory Option			
			I[b]		V[c]	
	10^6 $	% of sales	10^6 $	% of sales	10^6 $	% of sales
Sales	28.22	100.00	28.22	100.00	28.22	100.00
Expenses	27.45	97.26	27.80	98.52	28.35	100.46
Gross profit	0.78	2.74	0.42	1.48	(0.14)	(0.46)
Taxes	0.39	1.37	0.21	0.74	0.00	0.00
Net income	0.39	1.37	0.21	0.74	(0.14)	(0.46)
Return on assets, %	1.26		0.68		(0.50)	

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

Return on assets is 0.68 percent in Option I and negative 0.50 in Option V as compared to 1.26 percent in the base case.

Table 9-54 presents comparative coverage and debt/equity ratios for the regulatory options. Change in coverage ratio as a function of debt level assumed is greatest in Option V. This option shows the coverage ratio decreasing from 5.45 with zero percent new debt to 4.30 with 100 percent debt. The base case coverage ratio decreases from 5.45 with zero percent debt to only 4.52 with 100 percent debt. However, coverage ratios for all financing options used for each of the regulatory options still are above the 3.0 coverage benchmark.

The results of the analysis indicate that product cost is expected to increase by slightly over one-half of a percent at most. New steam costs for the regulatory options comprise a relatively small portion of average product cost. Profitability shows a decline as a result of the regulatory options when compared to the base case. Return on assets, for example, decreases from 1.26 percent in the base case to negative 0.50 percent in Option V.

With regard to financing capability, the analysis of coverage ratios indicates that new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark. The industry maintains a relatively stabilized solvency position even when 100 percent debt financing is assumed, because of its moderate leverage position.

TABLE 9-54. CAPITAL AVAILABILITY: LIQUOR DISTILLING MODEL FIRM

Financial indicator	Base Case[a]	Regulatory Option I[b]	Regulatory Option V[c]
Coverage ratio			
Percent financed by debt			
0	5.45	5.45	5.45
25	5.19	5.13	5.10
50	4.95	4.83	4.81
75	4.73	4.59	4.53
100	4.52	4.35	4.30
Debt/equity ratio			
Percent financed by debt			
0	0.27	0.27	0.27
25	0.29	0.30	0.29
50	0.32	0.32	0.33
75	0.34	0.35	0.36
100	0.37	0.39	0.39

[a] Base case regulations are the applicable SIP's for all pollutants.

[b] Regulatory Option I regulations for these boilers are SIP limits for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

[c] Regulatory Option V regulations for these boilers are 860 ng/J (2.0 lb/MMBtu) and 90-50% reduction for SO_2; 43 ng/J (0.1 lb/MMBtu) for PM; and 258 ng/J (0.6 lb/MMBtu) for NO_x.

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